

STEAM GENERATOR SINGLE-TUBE
RUPTURE ANALYSIS FOR SNUPPS PLANTS
CALLAWAY AND WOLF CREEK

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SUMMARY

The purpose of this report is to satisfy Licensing Conditions 2.C(11) for Kansas Gas and Electric Company Wolf Creek Generating Station and 2.C(11) for Union Electric Company Callaway Plant by submitting a revised steam generator tube rupture (SGTR) analysis.

Re-examination of the SGTR analysis was initiated by SNUPPS early in 1984 in response to three questions sent to SNUPPS in an informal transmittal by the NRC. The questions concerned:

1. operator action times following an SGTR event;
2. potential overflowing of the faulted SG, i.e., overflow of water into the steam line, and the consequences of overflow; and
3. the safety classification of components used to mitigate an SGTR event.

SNUPPS submitted preliminary responses to the NRC's questions via Reference 1. The submittal concluded that there was adequate assurance for safe interim operation of Callaway and Wolf Creek. The NRC requested additional information via Reference 2. SNUPPS met with the NRC on November 27, 1984 to present information responding to the NRC's requests. Information presented at the meeting was formally submitted by Reference 3. At the November 27 meeting it was agreed that SNUPPS would submit confirmatory RETRAN analyses of the worst case SGTR by December 31, 1985 and that commitment was documented in Reference 3.

This report is in response to that commitment. It also summarizes and updates information previously transmitted to the NRC. Therefore, this is a comprehensive report of all of the work done by Kansas Gas and Electric, Union Electric, and SNUPPS staff to address the NRC's questions about postulated SGTR events. The report describes:

1. salient aspects of the Callaway and Wolf Creek plant designs that differ from other Westinghouse PWRs and affect the response to a postulated SGTR;
2. extensive analyses performed with a SNUPPS-developed, fast-running computer code, to identify worst case single failures and produce preliminary results;
3. the bases for operator action times assumed in the analyses;
4. benchmarking of the RETRAN model for SGTR analyses;
5. RETRAN analyses of two "worst case" SGTR scenarios, one that approaches overflow, and one that results in maximum offsite doses;
6. steam line integrity if overflow should occur; and
7. bases for a Technical Specification for the main steam line atmospheric relief valves.

The analyses in this report show that the worst case single failure with respect to SG overfill is unique to the SNUPPS design and is a failure in the full open position of the auxiliary feedwater control valve from the motor-driven AFW pump to the faulted SG. With this postulated single failure and conservatively long operator response times, based on plant simulator experiences and other data, it is shown that SG overfill does not occur.

The worst case single failure with respect to offsite dose is a failure in the open position of the atmospheric relief valve on the faulted SG. With this postulated single failure and iodine spiking models, prescribed by Standard Review Plan (SRP) 15.6.3, offsite doses are less than the guidelines of SRP 15.6.3. Per NRC generic letter 85-19 (Reference 7), iodine spiking has been conservatively treated in the Technical Specifications and the SRP.

All of this information is submitted to the NRC for its review and approval.

2.0 OPERATOR RESPONSE TIMES

2.1 Introduction

Operator actions in response to an SGTR are assumed to follow plant specific emergency procedures, which are based on procedure E-3 (SGTR response) and related procedures of the generic emergency response guidelines (ERGs) for Westinghouse plants. The procedures for the Callaway plant were originally based on the basic version of the ERGs, but have been recently revised to conform to Rev. 1 of the ERGs. The procedures for the Wolf Creek plant are based on Rev. 1 of the ERGs.

The timing of operator actions has been estimated using data from three sources: (1) plant simulators, (2) an SGTR event at the Ginna plant, and (3) draft standard ANS 58.8, Rev. 2. Heaviest weight has been placed on the simulator data because it reflects what SNUPPS plant operators have done, using plant-specific procedures on SNUPPS-specific simulators. The Ginna event predated the creation of the generic ERGs. An earlier SGTR at the Prairie Island plant has not been factored into the bases because the tube break was smaller than a double-ended rupture and the accident progressed more slowly than at Ginna and in the cases postulated in this report.

The response of the operators to an SGTR can be considered to be a five-phase process: (1) identify that an SGTR has occurred, identify the faulted SG, and isolate the faulted SG; (2) prepare to cool the RCS, in order to maintain subcooling after subsequent depressurization; (3) cool and then depressurize the RCS, to reduce the primary to secondary leak rate; (4) terminate safety injection, to prevent repressurization of the RCS; and (5) take the plant to cold shutdown conditions, in order to establish cooling by the residual heat removal (RHR) system. This process and the timing of operator actions are discussed below. The results are summarized in Table 2-1.

2.2 Identification and Isolation of Faulted SG

Based on observation of operator responses to SGTR events on the plant simulators, the operators identify the occurrence of an SGTR very early in the accident sequence, from high radioactivity in the condenser off-gas and/or in the SG blowdown. An early indication of which SG contains the break is reduced feedwater flow, because the feedwater controller reduces feedwater flow to the faulted SG in order to maintain water level. In many cases, the SNUPPS plant operators have identified the faulted SG prior to occurrence of reactor trip. In general, the actions necessary to identify and isolate the faulted SG can be accomplished from within the control room.

For isolation of the faulted SG, the E-3 procedure calls for: (1) closure of MSIVs and bypass valves; (2) verify affected SG ARVs are closed; (3) close affected SG steam supply valve to the turbine driven AFW pump; and (4) when the SG water level in narrow range, stop all AFW flow to affected SGs.

A conservatively long estimate of the time required for operators to complete isolation of the faulted SG is 16 minutes after occurrence of the SGTR. This estimate is based on observed operator response times of: (1) 12 to 16 minutes on the Callaway simulator, using ERG Revision 0, (2) [] minutes on the Callaway simulator using ERG Revision 1, and (3) 10 minutes during Westinghouse Owners Group (WOG) verification and validation of Rev. 1 of the ERGs on the Seabrook simulator. 4.i(a,b,c)

In the Ginna event, isolation of the faulted SG was accomplished in 13 minutes, which confirms the conservatism of the 16-minute estimate for the SNUPPS plants.

Draft standard ANS 58.8, Rev. 2 bases assumed operator action times on an initial period for the operators to assess what is happening and then an allowance of 1 minute for each manipulation to be performed in the control room. Since a double-ended SGTR with occurrence of the worst single failure is classified as a Condition IV event, the draft of ANS 58.8, Rev. 2 would have the operators take no action during an initial period of 20 minutes. That estimate is inconsistent with procedural training, simulator data, and the Ginna event and it has not been used. A better estimate is the 10 minutes specified for a Condition III event. The number of manipulations to isolate the faulted SG is 2 to 4, depending on which SG is faulted. If combined with a 10 minute initial time, this gives a result generally consistent with the simulator data.

The worst case single failure with respect to potential SG overflow in the SNUPPS plants, as described in Section 3 of this report, is a failure in the open position of the auxiliary feedwater (AFW) control valve on the discharge of the motor-driven AFW pump feeding the faulted SG. If the single failure is such as to prevent this valve from being closed from the control room, feedwater flow to the faulted SG can be isolated by stopping the motor-driven AFW pump using a switch in the control room. Procedural guidance for this situation has been provided to the operators and, based on exercises performed on the Callaway simulator, isolation of the faulted SG would be accomplished within the 16 minutes developed above.

The worst case single failure with respect to offsite dose in the SNUPPS plants, as also described in Section 3, is a failure in the open position of the atmospheric relief valve (ARV) on the faulted SG. In this case, isolation of the faulted SG requires that the block valve ahead of the ARV be closed. This is a manually actuated valve located in the steam tunnel. A conservatively long estimate of the time to close the block valve is 20 minutes after the ARV fails open. When the faulted SG is finally isolated by block valve closure, the water level in the faulted SG is off-scale low and therefore, in accordance with the E-3 procedure, AFW flow to the faulted SG is maintained until the specified minimum water level is reached.

2.3

Initiate RCS Cooldown

Following isolation of the faulted SG, the E-3 procedure calls for: (1) resetting the SI signal; (2) resetting containment isolation signals; (3) reestablishing instrument air to containment; (4) stopping the RHR pumps; and (5) waiting until the water levels in the intact SGs reach a prescribed level.

A conservatively long estimate of the time at which RCS cooldown can be initiated is 24 minutes after occurrence of the SGTR for cases in which overfill of the faulted SG is a potential concern. The bases for this value are observed operator response times of: (1) 22 to 24 minutes on the Callaway simulator using ERG Revision 0, (2) [] minutes on the Callaway simulator using ERG Revision 1, and (3) 23 minutes during WOG verification and validation of Rev. 1 of the ERGs on the Seabrook simulator. 4.i(a,b,c)

In the Ginna event, cooldown of the RCS was initiated 16 minutes after occurrence of the SGTR, which supports the above estimate.

The number of manipulations to be performed by operators in the control room during this interval is from 7 to 10, depending on whether it is necessary to throttle AFW flow to control water level in the intact SGs. Therefore, ANS 58.8 guidance would be 7 to 10 minutes after isolation of the faulted SG, which is generally consistent with the simulator data. In the event the ARV on the intact SG has been isolated because of leakage, experience has shown the valve can be opened within 5 to 10 minutes, which is within the bounds of operator action times used in this report.

For the postulated single failure that maximizes offsite doses, i.e., a failed open ARV on the faulted steam generator, the time of initiation of RCS cooldown is governed by the requirements imposed by the E-3 procedure to have a water level of at least 4 percent in all steam generators and a pressure of at least 615 psig in the faulted SG. The time to reach these conditions is significantly longer than the 24-minute estimate that has been applied to the potential overfill cases above.

2.4

Cooldown and Depressurization of the RCS

Cooldown of the RCS is accomplished by releasing steam from the intact SGs to the condenser, if offsite power is available, or to the atmosphere through the ARVs, if offsite power is lost. The Callaway procedures define a maximum rate of depressurization of the intact SGs of 100 psi per 50 seconds. The Wolf Creek procedure specifies that steam be released at the maximum rate.

Depressurization of the RCS is accomplished after RCS cooldown has been completed. The E-3 procedure specifies use of normal pressurizer spray, if it is available, or opening of a pressurizer PORV, if normal spray is not available, as is the case if offsite power is lost.

A conservatively long estimate of the time required to complete cooldown and depressurization of the RCS following occurrence of an SGTR, for cases where overfill is a potential concern and where offsite power is lost, is 35 minutes. This estimate is based on observed operator action times of: (1) 30 to 35 minutes on the Callaway simulator using ERG Revision 0, (2) [] minutes 4.i(a,b,c) on the Callaway simulator using ERG Revision 1, and (3) 33 minutes during WOG verification and validation of Rev. 1 of the ERGs on the Seabrook simulator. The operators must perform seven manipulations. Therefore, ANS 58.8 guidance is 7 minutes to perform cooldown and depressurization, which is generally consistent with the simulator data.

For the worst case SGTR with respect to offsite doses, as described in Sections 3 and 4, cooldown of the RCS is initiated at a lower pressure in the intact SGs and therefore takes longer than the times given above. After completion of cooldown, a 3-minute delay is assumed prior to initiating RCS depressurization. The time to depressurize is calculated explicitly.

2.5 Termination of Safety Injection

Following completion of RCS depressurization to a pressure approximately equal to that of the faulted SG, the E-3 procedure requires several conditions to be met prior to terminating safety injection (SI). These are: a minimum RCS pressure, a minimum RCS subcooling based on core outlet thermocouples, and a minimum pressurizer level. The analyses of Section 4 show that all of these conditions are satisfied when RCS depressurization is terminated. The operators then perform three manipulations to stop SI flow.

Based on the existence of all necessary conditions for termination of SI flow and the guidance of ANS 58.8 of 1 minute per manipulation, it is assumed that the operators can terminate SI within 3 minutes after completion of RCS depressurization. This is a conservative estimate, because the three manipulations required to terminate SI are performed on one control panel.

2.6 Transition to Cold Shutdown

The immediate situation after termination of SI is that RCS pressure is a few hundred psi higher than the pressure in the faulted SG and the break flow, though reduced, still continues. The first requirement is to equalize pressures in the RCS and the faulted SG. Continued steam release from the intact SGs is necessary to remove decay heat and a slight reduction of intact SG pressure will reduce RCS temperature, shrink RCS volume, and reduce RCS pressure. Continued break flow also tends to reduce RCS pressure. It is assumed that pressure equalization is achieved within 5 minutes after termination of SI.

After pressure equalization is achieved, the E-3 procedure prescribes a number of actions pertaining to the status of offsite power, the diesel generators, pressurizer heaters, and reactor coolant pumps. Throughout these steps, the RCS and steam generator pressures and temperatures remain essentially constant and break flow essentially zero.

When all steps in procedure E-3 have been completed, the procedures specify cooldown and depressurization to cold shutdown conditions, so that the RHR system can be brought into operation. The major problem in doing this is that the faulted SG contains hot water and steam and tends to act as a pressurizer for the RCS, particularly if offsite power is unavailable and reactor coolant pumps cannot be operated. Although the RCS temperature can be reduced by release of steam from the intact SGs, RCS pressure cannot be reduced until the temperature (and pressure) of the faulted SG are reduced.

The ERGs provide three alternative methods to make the transition to RHR cooling conditions. These are:

- ES-3.1, Post SGTR Cooldown Using Backfill;
- ES-3.2, Post SGTR Cooldown Using Blowdown; and
- ES-3.3, Post SGTR Cooldown Using Steam Dump.

In ES-3.1, the RCS pressure is reduced below that of the faulted SG, so that water from the faulted SG can flow back into the RCS. The faulted SG is cooled and depressurized by addition of cold AFW. In ES-3.2, the faulted SG is cooled and depressurized by using the SG blowdown system to remove hot water and the AFW system to add cold water. In ES-3.3, the faulted SG is cooled and depressurized by releasing steam to the condenser or to the atmosphere. The method of ES-3.3 results in more rapid cooldown and depressurization than either of the other methods.

Following pressure equalization between the RCS and faulted SG and during the transition to RHR cooling, there is no further radioactivity release to the atmosphere of consequence unless ES-3.3 is employed in the absence of offsite power. That would result in release of steam and radioactivity from the faulted SG directly to the atmosphere.

For the worst case dose analysis, it is assumed that the transition to cold shutdown is effected using ES-3.3 in the absence of offsite power, in order to establish an upper bound to the offsite doses. However, it is most unlikely that steam release to the atmosphere would be the selected method to terminate this case, in which it is postulated that the ARV fails in the open position and the block valve has to be closed manually.

For the worst case overflow analysis, the indicated water level in the faulted SG would be offscale high and the operators would have to assume the possibility of water in the steam line. Under that condition, use of ES-3.3 is prohibited. Cooldown to RHR conditions would be accomplished using one of the other methods and there would be no further releases of radioactivity to the atmosphere.

TABLE 2-1

SUMMARY OF OPERATOR ACTION TIMES
(Minutes after Occurrence of SGTR)

<u>Operator Action</u>	<u>Times for Worst Case Overfill</u>	<u>Times for Worst Case Dose</u>
Isolate Faulted SG	16	28.4 (Close block valve 20 min. after ARV fails open)
Initiate RCS Cooldown	24	38.6 (When minimum SG levels and minimum RCS pressure are re-established)
Complete Depressurization of RCS	35	54.3 (Calculated SG & RCS depressurization times, plus 3 minutes)
Terminate SI	38	57.3 (3 minutes after RCS depressurization is complete)
Equalize RCS & Faulted SG Pressures	43	62.3 (5 minutes after SI termination)
Initiate RHR Cooling	Not significant	Within 2 hours (to maximize 0-2 hour dose)

3.0 SELECTION OF REFERENCE WORST CASE(S) SGTR EVENT

3.1 SNUPPS Secondary Systems

The SNUPPS secondary systems are generally similar to those of other Westinghouse PWRs. A composite schematic diagram of portions of the main steam system, the main feedwater system and the auxiliary feedwater system is given in Figure 3-1.

The auxiliary feedwater system consists of two motor-driven pumps, one steam turbine-driven pump and associated piping, valves, instruments, and controls. In addition to remote manual-actuation capabilities, the system is aligned to be placed into service automatically in the event of an emergency. Any one of the following conditions will cause automatic startup of both motor-driven pumps:

- a. Two out of four low-low level signals in any one steam generator
- b. Trip of both main feedwater pumps
- c. Safeguards sequence signal (initiated by safety injection signal or loss-of-offsite power)
- d. Class IE bus loss of voltage sequence signal (i.e., loss-of-offsite power)

The turbine-driven pump is actuated automatically on either of the following signals:

- a. Two out of four low-low level signals in any two steam generators
- b. Class IE bus loss of voltage sequence signal (i.e., loss-of-offsite power)

Specific features of the SNUPPS secondary systems that are pertinent to SGTR events are as follows:

1. The SG atmospheric relief valves (ARVs) are class IE, fully qualified to safety requirements, and actuated from the control room. The control power is DC and the actuating gas supply is from a seismically qualified accumulator. The block valves are locally, manually actuated.
2. There are 5 safety valves on each steam line, located between the ARV and the main steam isolation valve (MSIV).
3. The MSIVs are Class IE, fully qualified to safety requirements, and actuated from the control room. All valves can be closed by a single switch in the control room.
4. The main feedwater pumps are steam-driven. They stop on SG high-high level, closure of MSIVs, or manual closure of the steam-supply stop valve.
5. The feedwater isolation valves (FWIVs) are Class IE, fully qualified to safety requirements, and actuated from the control room. Signals that close FWIVs include SI signal, low-low SG level (23.5% narrow range) or high-high SG level (78% narrow range).

6. Each motor driven AFW pump delivers a design flow of 500 gpm to two SGs. The turbine-driven AFW pump delivers a design flow of 1000 gpm to four SGs. Flow balancing orifices are provided in the pump discharge lines.
7. The control valves on the discharge of the motor-driven pumps are automatically positioned to limit the total AFW flow to any SG to a nominal value of 320 gpm. The total tolerance on this control including errors is ± 70 gpm.
8. Steam is supplied to the turbine-driven AFW pump from the steam lines of SGs B and C.
9. The PORVs on the pressurizer and the PORV block valves are Class IE and fully qualified to safety requirements. The valves are electrically powered and actuated from the control room.

3.2 Spectrum of SGTR Events Analyzed

To select the reference worst case(s), a spectrum of SGTR events was analyzed.

3.2.1 Selection of Worst Case Conditions

Major concerns associated with a steam generator tube rupture (SGTR) are: (1) the potential for overflow of the faulted steam generator with water entering the main steam line resulting in water relief through an ARV and (2) failure of an ARV in the open position leading to continued release of steam generator fluid and contained radioactivity. To examine these concerns the SGTR Scoping Code (see Appendix B for description) in conjunction with other analyses was used to evaluate the sensitivity of SGTR events to a number of parameters. Parameters investigated were: single active failures, availability of offsite power, location of tube rupture, operator action times, power level, and iodine spiking.

3.2.1.1 Potential Overflow

3.2.1.1.1 Single Active Failure

The effect of single failures on the potential for overflow from the sources of water to a faulted steam generator have been investigated. There are three sources of water to a faulted steam generator: (1) main feedwater flow; (2) leakage from the primary system; and (3) auxiliary feedwater flow.

1. Main feedwater flow is not the most limiting source of potential overflow of the faulted steam generator for the following reasons:

- The SNUPPS plants have a single-failure proof, Class IE system, with 2-out-of-4 logic that trips the main feedwater pumps on high-high SG level. The setpoint for this function is 78% of narrow range level. Consequently, main feedwater flow will always be terminated shortly after the SG water level exceeds 78% with the plant operating in the power range (i.e., with steam voids in the SG).
 - Since the SG level control system maintains SG level at $50 \pm 5\%$ of narrow range level during normal operation, a failure of the feedwater controller would be required before trip of the main feedwater pumps on high SG level could occur.
2. Extended leakage from the primary system, resulting from a single failure, is not the limiting case with regard to steam generator potential overfill, for the following reasons:
- Termination of primary to secondary leakage requires that: (1) RCS temperature be reduced; (2) RCS pressure be reduced; and (3) safety injection be terminated.
 - The first function, reduction of RCS temperature, can be accomplished with the atmospheric relief valve (ARV) on only one of three intact SGs. Therefore, a failure of one or two ARVs cannot prevent this function from being performed.
 - The second function, reduction of RCS pressure, can be accomplished with only one of the two pressurizer power operated relief valves (PORVs). Therefore, failure of a PORV or its block valve cannot prevent this function from being performed.
 - The third function, termination of SI, can be accomplished by putting the SI pumps into pull-to-lock with handswitches in the control room. The pull-to-lock function overrides a potential failure in the SI reset circuitry, so that a single failure of SI reset would not prevent SI flow from being terminated. The procedural guidance with respect to termination of SI has been clarified since the SGTR event at the Ginna station in 1982, during which the operators allowed SI to continue and repressurize the RCS. Therefore, failure to terminate SI is not considered the most limiting failure with respect to SG potential overfill.
 - The water addition rate, with a postulated failure of the AFW control valve, is much higher than the primary to secondary leakage flow for a single double-ended tube rupture.
3. If there is no single failure in the AFW system, maximum AFW flow is 390 gpm (320 nominal plus control tolerance). This case is less limiting with respect to SG potential

overflow than the large AFW flow rates that could result from a postulated single failure in the AFW system. Failure in the wide-open position of the control valve on the discharge of the MD pump feeding the faulted SG coupled with the contribution from the turbine driven AFW pump has the potential for supplying 723 gpm to the faulted SG. This would occur under the following circumstances. The control valve for one intact SG, the one supplied by the same MD AFW pump as the faulted SG, is assumed to limit AFW flow to the low side of its control band. Based on an analysis of the AFW system, the AFW flow to the faulted SG is then 723 gpm and the flow to the other SG is 305 gpm.

3.2.1.1.2 Availability of Offsite Power

The potential for overflow is not strongly dependent on the availability of offsite power. However, the potential for overflow is slightly greater if it is assumed that offsite power is lost when the reactor trips, because auxiliary feedwater flow is initiated earlier. Furthermore, if overflow should occur, the offsite doses are significantly greater if offsite power is lost. For these reasons, it has been assumed that offsite power is lost coincident with reactor trip.

3.2.1.1.3 Location of Tube Rupture

The tube rupture could be located anywhere along a U-tube; however, a cold-leg tube rupture located at the top of the tube sheet on the shortest tube results in the greatest total mass leak rate and, consequently, produces the greatest potential for overflowing the steam generator (see the expression for leak rate in Appendix D). This results physically because, for a given pressure differential, the break flow increases as fluid temperature decreases. This result was also demonstrated in Table 1-5.1 of Reference 3.

3.2.1.1.4 Operator Action Times

To determine the sensitivity of potential overflow to operator action times, various operator action times to isolate the faulted steam generator and terminate auxiliary feedwater flow, to begin RCS cooldown, to complete RCS cooldown and depressurization, and to terminate safety injection flow have been assumed in the analyses.

3.2.1.1.5 Power Level

Reactor Core power level for the analyses has been established at 102% of licensed power. As the RCS pressure decreases during the event, the overtemperature delta T trip setpoint is approached and the control system will runback the turbine and reduce the reactor core power level in steps and thus prevent tripping the reactor on overtemperature delta T. Trip will ultimately occur upon reaching the low pressurizer pressure reactor trip setpoint. However, delaying reactor trip, as discussed above, does not

yield the worst case for potential overfill, since the integrated auxiliary feedwater flow prior to termination will be less. For the potential overfill case, the control system is assumed not to function and reactor trip occurs early when the overtemperature delta T trip setpoint is reached. Thus, the integrated auxiliary feedwater flow is maximized. If one were to assume a lower power level, the time to reactor trip would be increased and the integrated auxiliary feedwater flow would be reduced.

Another reason for performance of the SGTR analysis at the highest initial power level is that it is consistent with the condition for inducing the largest thermal stresses in the steam generator tubing. As the event of interest is the rupture of a steam generator tube, maximizing the thermal stress will ensure the closest approach to the rupture limit.

3.2.1.1.6 Iodine Spiking

Doses for the potential overfill case were determined for comparison with those resulting from the stuck-open ARV case. Two cases of iodine spiking (increase in iodine concentration in the reactor coolant) were analyzed, in accordance with the NRC's Standard Review Plan 15.6.3.

3.2.1.1.7 Sensitivity Study

Based on the preceding evaluations, a number of calculations were performed with the scoping code to determine the degree of filling of the faulted steam generator and two-hour site boundary doses.

Results of these calculations show that longer action times result in greater potential for overfill of the steam generator. Doses resulting from releases associated with the potential overfill analyses are much smaller than those associated with a failed open ARV.

3.2.1.2 Maximum Potential Dose

3.2.1.2.1 Single Active Failure

The single failure with the largest dose potential is failure of an ARV in the wide-open position. This failure releases radioactive steam directly to the atmosphere and, if the ARV is left in the open position, has the potential of releasing the entire contents of the faulted steam generator secondary side to the atmosphere.

3.2.1.2.2 Availability of Offsite Power

The loss of offsite power (LOOP) results in more iodine being released to the atmosphere and higher offsite doses than if offsite power is available. If offsite power is lost, steam and iodine are released to the atmosphere through the atmospheric relief valve (ARV) and/or steam line safety valves.

3.2.1.2.3 Location of Tube Rupture

A hot-leg tube rupture located at the top of the tube sheet on the shortest tube results in the greatest offsite dose because this location produces the highest flashed fraction of leaked reactor coolant.

3.2.1.2.4 Operator Action Time

Steam release through a stuck-open ARV is terminated by manual closure of the block valve. The longer it takes the operators to close the block valve, the higher the offsite dose will be. It has been determined (Section 2.2) that the block valve can be closed within 20 minutes.

3.2.1.2.5 Power Level

Power level for the stuck-open ARV case is set at 102% of engineered safety features design core thermal power output. This power level results in the highest reactor coolant hot-leg temperature during this transient and thus the highest flashed fraction of leaked reactor coolant to the SG.

3.2.1.2.6 Iodine Spiking

Two cases of iodine spiking (increase in iodine concentration in reactor coolant) were analyzed, in accordance with the NRC's Standard Review Plan 15.6.3. It has been found that Case 1, in which the iodine spike is assumed to be initiated by reactor trip is the more limiting case.

3.2.1.3 Reference Worst Cases for RETRAN Analyses

Based on the analyses with the scoping code and the operator action times established in Section 2, key parameters were selected for more detailed analyses with RETRAN of the worst case potential overfill and the worst case stuck-open ARV. Table 3-1 lists the parameters for the potential steam generator overfill case and Table 3-2 lists the parameters for the stuck-open ARV case. As appropriate, Tables 3-1 and 3-2 provide the bases for the selection of the parameter value or the error associated with each parameter.

Table 3-1. Potential Overfill Case - Initial Conditions and Input Parameters

<u>Item</u>	<u>Value</u>	<u>Bases</u>
Single failure	AFW flow control valve fails open	Single failure with greatest potential for overfill.
Break location	Cold leg, at tube sheet, shortest SG tube	Location that maximizes total leaked reactor coolant.
Core inlet temperature	558.8 + 6.5°F	[4.i(a,b,c)]
NSSS power	102% (3425 MW basis)	See Section 3.2.1.1.5
RCS pressure (pressurizer)	2220 psia	[4.i(a,b,c)]
Decay heat	1.0 x [1971 ANS] (3411 MW basis)	Including no additional margin in decay heat minimizes reactor coolant temperatures, thus maximizes reactor coolant density which maximizes total leaked reactor coolant.
RCS flow	Thermal Design Flow	[4.i(a,b,c)]
SG initial level	55% Narrow Range	Nominal SG level plus error allowance maximizes initial SG water mass and thus maximizes potential for overfill.
AFW flow - faulted SG	723 gpm	Maximum AFW flow resulting from single failure - maximizes integrated AFW flow.
AFW flow - intact SG	305 + 2 x 390 gpm up to faulted SG isolation; maximum of 3 x 390 gpm after isolation	Maximum AFW flow to the intact SGs provides maximum cooling to the reactor coolant which increases density of reactor coolant and thus increases total leaked reactor coolant.

Table 3-2. Stuck-Open ARV - Initial Conditions and Input Parameters

<u>Item</u>	<u>Valve</u>	<u>Bases</u>
Single failure	Failed open ARV	Single failure that maximizes offsite dose.
Break location	Hot leg, at tube sheet, shortest tube	Produces greatest flashed fraction of leaked reactor coolant and thus largest offsite dose.
Core inlet temperature	558.8 + 6.5°F	Maximum expected inlet temperature maximizes T_H and thus maximizes flashed fraction of leaked reactor coolant.
NSSS power	102% (3579 MW basis)	High power results in high reactor coolant hot leg temperature initially and during natural circulation decay heat removal and thus the highest flashed fraction of leaked reactor coolant.
RCS pressure (pressurizer)	2280 psia	Nominal pressure plus error allowance maximizes leakage flow and thus produces greatest flashed fraction and resulting offsite doses.
Decay heat	1.2 x [1971 ANS] (3565 MW basis)	Adding margin to the nominal decay heat maximizes heat to be transferred and thus maximizes release of steam and contained radioactivity to the atmosphere.
RCS flow	Thermal Design	Use of thermal design flow instead of a higher flow results in a larger core ΔT which maximizes T_H and thus maximizes flashed fraction of leaked reactor coolant.
SG initial level	45% Narrow Range	Nominal SG level minus error allowance minimizes the amount of secondary water available for release of decay heat by vaporization and thus maximizes the amount of leaked reactor coolant that is vaporized and thus the offsite dose is maximized.

Table 3-2. Stuck-Open ARV - Initial Conditions and Input Parameters
(continued)

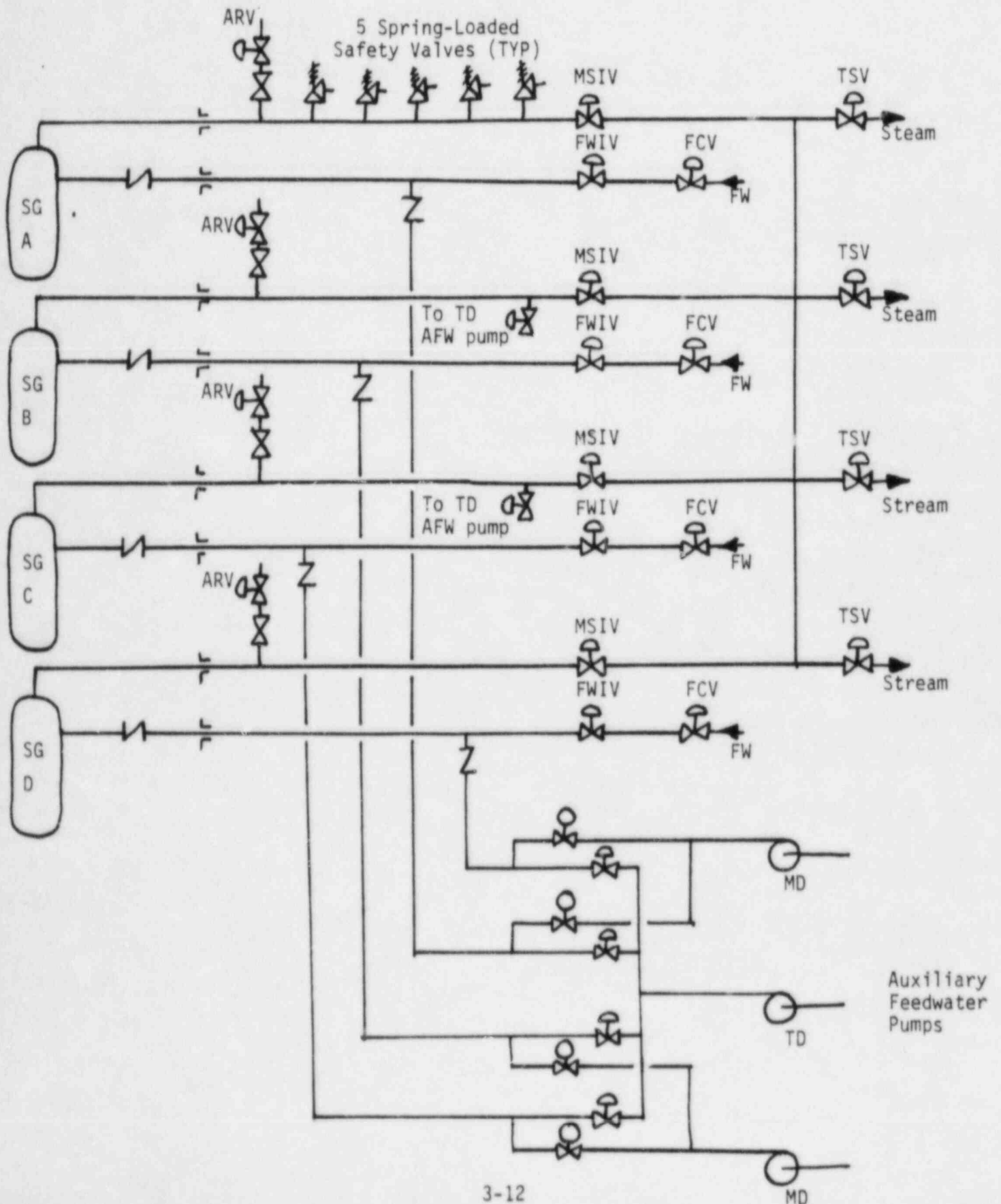
<u>Item</u>	<u>Values</u>	<u>Bases</u>
AFW flow - faulted SG	250 gpm	Minimum expected AFW flow to the faulted SG minimizes RCS cooling, maintains RCS temperatures high, and thus maximizes flashed fraction of leaked reactor coolant. Also see SG initial level.
AFW flow - intact SG	3 x 250 gpm	Minimum expected AFW flow to the intact SGs minimizes RCS cooling, maintains RCS temperatures high, and thus maximizes flashed fraction of leaked reactor coolant.
SG initial pressure	950 psia	Minimum expected steam pressure maximizes leaked reactor coolant and thus maximizes dose.
ARV setpoint	1125 psig - 4% uncertainty	Nominal setpoint less uncertainty gives early opening of the ARV and thus maximizes release to the atmosphere.
AFW initiation delay	60 seconds after LOOP	Maximum expected delay for AFW initiation maximizes the amount of leaked reactor coolant that is vaporized and thus maximizes offsite dose.
SI delay	25 seconds after LOOP	Maximum expected delay for SI initiation minimizes addition of cold water to the RCS which maximizes reactor coolant temperatures and thus maximizes flashed fraction of leaked reactor coolant.
MFW isolation valve stroke time	2 seconds	Minimum expected stroke time, by limiting addition of cold water to SG, minimizes heat removal from the reactor coolant, maximizes reactor coolant temperatures and thus maximizes flashed fraction of leaked reactor coolant. Also see SG initial level.

Table 3-2. Stuck-Open ARV - Initial Conditions and Input Parameters
(continued)

<u>Item</u>	<u>Values</u>	<u>Bases</u>
Offsite Power Availability	LOOP at reactor trip signal	With LOOP, steam dump and the condenser are unavailable for retention of any of the leaked radioactivity thus maximizing releases to the atmosphere.
OTAT setpoint	[]	[] 4.i(a,b,c)

FIGURE 3-1

Partial Composite Schematic Diagram of SNUPPS Secondary Systems



4.0 RETRAN Analysis

4.1 Introduction

In previous sections, the failed open auxiliary feedwater control valve has been identified as the reference worst case with regard to the possibility of overfilling the faulted steam generator. It is also identified that a stuck open atmospheric relief valve (ARV) represents a limiting case for which radiological release to the atmosphere is maximized. In this section, detailed SGTR transient analyses are presented for these cases.

RETRAN-02 (Reference 4) is a thermal hydraulic computer code which is widely used in the utility industry for transient analysis. The NRC has issued a Technical Evaluation Report (Reference 5) which addresses the acceptance of the code for use in licensing applications (see Appendix B for details). A detailed description of modeling techniques is also given in Appendix B.

RETRAN has been used to analyze the SGTR event based on the initial conditions and assumptions given in the SNUPPS FSAR. As illustrated in Appendix C, RETRAN results are in very good agreement with those calculated by LOFTRAN (Westinghouse computer code).

Following is a description of single failure analyses and associated results in connection with a failed open auxiliary feedwater control valve and a stuck open ARV. It is noted that initial conditions and parameters which are conservative for overfilling the steam generator may not be conservative as far as maximizing the radiological release is concerned. Therefore, they are selected on the bases of being conservative with regard to the specific single failure being analyzed.

4.2 Failed Open Auxiliary Feedwater Control Valve

4.2.1 Introduction

One of three questions (Reference 1) of which NRC has requested additional information on the SGTR analysis is the overfilling of the steam generator. This analysis assumes the worst case single failure, limiting values of plant parameters, and conservative operator response times, as described earlier.

4.2.2 Analysis Methodology

4.2.2.1 Analysis Assumptions

Conservative initial conditions and assumptions as listed in Section 3 are used to maximize the likelihood of overfilling the faulted steam generator. Operator response times are as summarized in Table 2-1. Additional assumptions are as follows:

1. The break flow is determined from resistance-limited flow or critical flow for which the primary to secondary pressure differential is the driving force (see Appendix D). The total break flow is the sum of leakage arising from the long and short sections of the ruptured tube.
2. Prior to the reactor trip, the normal feedwater flow matches the steam flow in the intact steam generators. For the faulted steam generators, the total feed flow (including the break flow) matches the steam flow.

4.2.2.2 Automatic Action

As a result of tube rupture which occurs at time zero, the plant system or equipment responds to the loss of primary coolant in the following manner:

1. Due to the loss of reactor coolant, a decrease in RCS pressure results in a reactor trip signal generated by exceeding the overtemperature ΔT setpoint (Figure 4-1).
2. As a result of loss-of-offsite-power at reactor trip, the main condenser is not available and the secondary system pressure is regulated by the relief/safety valves. Reactor coolant pumps are tripped concurrently and normal feedwater is terminated to all steam generators.
3. Auxiliary feedwater is initiated after the loss-of-offsite power.
4. Safety injection signal is generated as the pressurizer pressure reaches a low pressure setpoint.

4.2.2.3 Operator Action

The recovery procedure requires proper and timely operator actions to mitigate the accident. As mentioned in Section 2, operator response times are categorized into five major steps summarized below. The RETRAN analysis simulated operator action for the first four steps only.

1. Isolation of Faulted Steam Generator

After reactor trip, the steam generator level is increasing as a result of the failed open auxiliary feedwater control valve (Figure 4-11). The operator identifies the equipment failure and terminates the feedwater to the faulted steam generator at sixteen minutes, at which time the indicated narrow range level in the faulted SG is offscale high (Figure 4-14). For the intact steam generators, feedwater flow is throttled to maintain narrow range level at approximately 15% (Figure 4-15).

2. Cooldown of Reactor Coolant System

Cooldown of the reactor coolant system is initiated at 24 minutes to achieve a margin of subcooling prior to depressurization. By discharging steam via the ARVs on the intact steam generators (Figure 4-13), the primary coolant reaches a subcooled temperature corresponding to the faulted steam generator pressure. The criterion is based on the core exit temperature in accordance with that given in the ERG E-3, Rev. 1. As the temperature of the primary coolant in the tube side of the faulted steam generator is lower than that of the secondary coolant, reverse heat transfer occurs. This results in a momentary reverse RCS flow in the loop with the faulted SG (Figure 4-6) and fluctuating RCS loop temperature (Figure 4-4).

3. Depressurization of Reactor Coolant System

Three minutes after the completion of cooldown, the primary system is depressurized by opening the PORVs on the pressurizer (Figure 4-3). Pressurizer level is increasing due to mass addition from safety injection flow (Figure 4-2). PORVs are closed when the RCS pressure is less than the faulted steam generator pressure. This reduces the pressure differential between the primary and secondary systems. The break flow approaches zero.

4. Termination of Safety Injection

Safety injection is terminated three minutes after completion of depressurization.

5. Transition to Cold Shutdown

Pressures in the RCS and faulted SG are equalized to terminate the break flow. Then, on an extended time basis, RCS temperature and pressure are reduced to conditions at which RHR cooling can be initiated. This requires cooling and depressurization of the faulted SG by one of three alternative procedures discussed in Section 2.6.

4.2.2.4 Radiological Consequences

The model used to calculate the radiological release (or dose) is described in Appendix F. Calculations are performed in accordance with the NRC Standard Review Plan 15.6.3.

4.2.3 Results

Table 4-1 provides a time sequence of events.

Throughout the period until the safety injection is terminated, the analysis indicates that overflowing the steam generator will not occur (Figure 4-11). The total leakage over this period of time is 85,817 pounds. At the termination of safety injection, the steam volume below the steam generator outlet nozzle is 178 cubic feet and the break flow is about 20 pounds/second. During the next 5 minutes it is assumed that the operators equalize primary and secondary pressures in the faulted SG and terminate break flow. The additional integrated break flow during this period is approximately 4000 pounds, assuming a linear reduction in differential pressure with time. At the time break flow is terminated, the steam volume below the SG outlet nozzle is approximately 91 cubic feet. Thus, with the use of conservative assumptions for operator action times and the worst single failure, overflow of the SG does not occur.

As indicated in Table 4-2, the radiological release to the atmosphere and resulting doses are minimal. This is caused by the low heat content of the auxiliary feedwater which lowers the steam generator pressure (Figure 4-9). As the secondary pressure is lower than the pressure setting associated with the ARV, the latter remains closed for most of the transient and this results in little activity release.

For the worst case overflow, there would be no significant releases of mass or radioactivity from the faulted SG to the atmosphere during the transition to cold shutdown conditions (see discussion in Section 2.6). Thus, the mass and radioactivity releases calculated by RETRAN are the total releases to the atmosphere from the faulted SG. The release of iodine activity from the intact SGs during this period has been calculated and is included in the results in Table 4-2.

Plots of parameters for the primary system, faulted and intact steam generators are shown in Figures 4-1 through 4-15.

4.3 Stuck Open Atmospheric Relief Valve

4.3.1 Introduction

This analysis assumes that loss-of-offsite-power occurs at the reactor trip. The system for steam dump to the condenser is therefore not available and steam is discharged to the atmosphere via ARVs. It is postulated that the ARV on the faulted steam generator fails open for a period of 20 minutes after it is first actuated during which time radioactivity is released to the atmosphere. Analysis assumptions are given in the next section and results are contained in Section 4.3.3.

4.3.2 Analysis Assumptions

Section 3 lists the initial conditions and assumptions which maximize the radiological release to the atmosphere. Operator

response times are as summarized in Table 2-1. Additional assumptions are given as follows:

1. The break flow is characterized by either resistance-limited subcritical flow or critical flow as defined in Appendix D.
2. The normal feed flow matches the steam flow in the same manner as described previously in Section 4.2.
3. Auxiliary feedwater injection is maintained to achieve narrow range level at approximately 15% in all SGs.
4. Prior to initiating RCS cooldown, narrow range level in all steam generators is greater than 4% and the ruptured steam generator pressure is higher than 615 psig.

4.3.3 Results

Table 4-3 provides a time sequence of events.

Reactor trip occurs automatically as a result of overtemperature ΔT . Loss of offsite power occurs at reactor trip. Pressures rise on the secondary side following reactor trip and the steam generator ARVs open to relieve excess secondary pressure (Figure 4-24).

The ARV for the faulted steam generator is assumed to fail open and steam release to continue for 20 minutes until the ARV block valve is manually closed. During this time pressures fall in all SGs (Figure 4-24) and RCS temperatures are also reduced as a consequence of heat removal by steam release from the faulted SG.

Cooldown is initiated and continues until RCS temperature is reduced to 50°F less than the ruptured steam generator saturation temperature.

At the termination of safety injection, the mixture volume in the faulted steam generator is less than 4,000 cubic feet (Figure 4-26) and does not pose a problem with regard to overflowing the steam generator.

The doses for this case have been calculated in accordance with the model described in Appendix F, are shown in Table 4-4, and are seen to be below the guidelines of SRP 15.6.3.

Parameters of primary and secondary systems are plotted as a function of time in Figures 4-16 through 4-30.

TABLE 4-1

TIME SEQUENCE OF EVENTS ASSOCIATED WITH
FAILED OPEN AUXILIARY FEEDWATER CONTROL VALVE

<u>Time (sec)</u>	<u>System Response/Operator Action</u>
0	Tube Rupture Occurs
144	Reactor Trip Signal
146	Reactor Trip
174	Auxiliary Feedwater Injection
309	Safety Injection Signal
324	Safety Injection
961	Terminate Auxiliary Feedwater to the Faulted SG
1330	Pressurizer PORV Open (setpoint at 2350 psia)
1334	Pressurizer PORV Closed (setpoint at 2200 psia)
1428	Pressurizer PORV Open
1432	Pressurizer PORV Closed
1441	Start RCS Cooldown
1851	Stop RCS Cooldown
2031	Start RCS Depressurization
2103	Stop RCS Depressurization
2283	Stop Safety Injection

TABLE 4-2

RADIOLOGICAL CONSEQUENCES OF A
STEAM GENERATOR TUBE RUPTURE WITH
FAILED OPEN AUXILIARY FEEDWATER CONTROL VALVE

	<u>Doses (rem)</u> <u>Limiting Site (Callaway)</u>
1. Case I	
Exclusion Area	
Boundary (0-2 hr)	
Thyroid, rem	.25
Whole body, rem	.007
Low Population Zone	
Outer Boundary (duration)	
Thyroid, rem	.06
Whole body, rem	.002
2. Case 2	
Exclusion Area	
Boundary (0-2 hr)	
Thyroid, rem	3.3
Whole body, rem	.01
Low Population Zone	
Outer Boundary (duration)	
Thyroid, rem	.45
Whole body, rem	.003

Case 1 - Accident induced iodine spiking per SRP 15.6.3
Case 2 - Pre-existent iodine spike per SRP 15.6.3

TABLE 4-3

TIME SEQUENCE OF EVENTS ASSOCIATED WITH
STUCK OPEN ATMOSPHERIC RELIEF VALVE

<u>Time (sec)</u>	<u>System Response/Operator Action</u>
501	Reactor Trip Signal
503	Reactor Trip
505	Faulted SG ARV Open
561	Auxiliary Feedwater Injection
569	Safety Injection Signal
584	Safety Injection
1705	Faulted SG ARV Closed
2397	Start RCS Cooldown
3021	Stop RCS Cooldown
3203	Start RCS Depressurization
3300	Stop RCS Depressurization
3481	Terminate SI

TABLE 4-4

RADIOLOGICAL CONSEQUENCES OF A
STEAM GENERATOR TUBE RUPTURE WITH
A STUCK OPEN ATMOSPHERIC RELIEF VALVE

	<u>Doses (rem)</u> <u>Limiting Site (Callaway)</u>
1. Case 1	
Exclusion Area	
Boundary (0-2 hr)	
Thyroid, rem	2.7
Whole body, rem	.018
Low Population Zone	
Outer Boundary (duration)	
Thyroid, rem	.36
Whole body, rem	.004
2. Case 2	
Exclusion Area	
Boundary (0-2 hr)	
Thyroid, rem	24.6
Whole body, rem	.04
Low Population Zone	
Outer Boundary (duration)	
Thyroid, rem	2.2
Whole body, rem	.007

Case 1 - Accident induced iodine spiking per SRP 15.6.3
Case 2 - Pre-existent iodine spike per SRP 15.6.3

FIGURE 4-1 REACTOR COOLANT SYSTEM PRESSURE
(Worst Case Potential Overfill)

4-10

RCS PRESSURE (PSIA)
(Thousands)

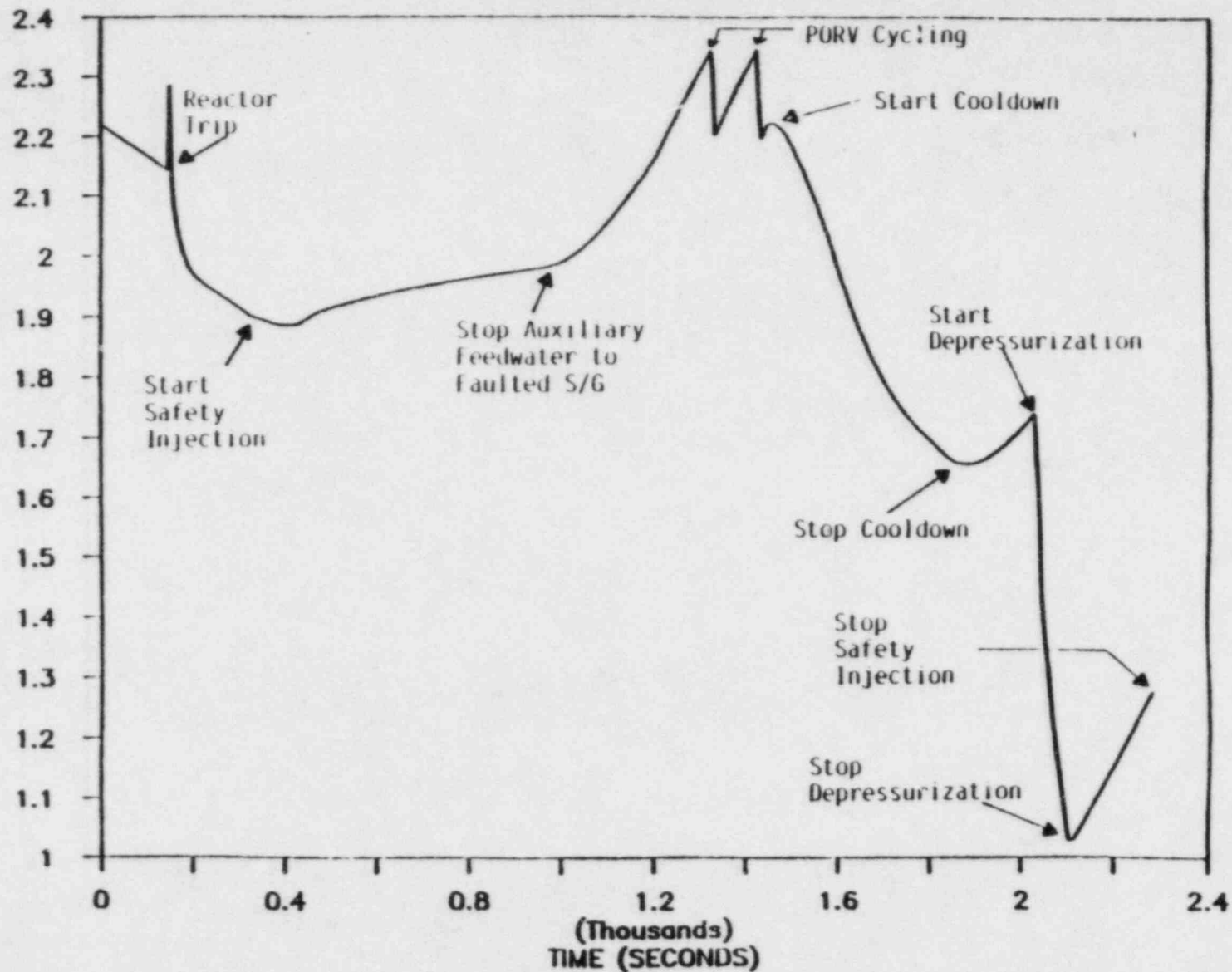


FIGURE 4-2 PRESSURIZER WATER LEVEL
(Worst Case Potential Overfill)

4-11

WATER LEVEL (FT)

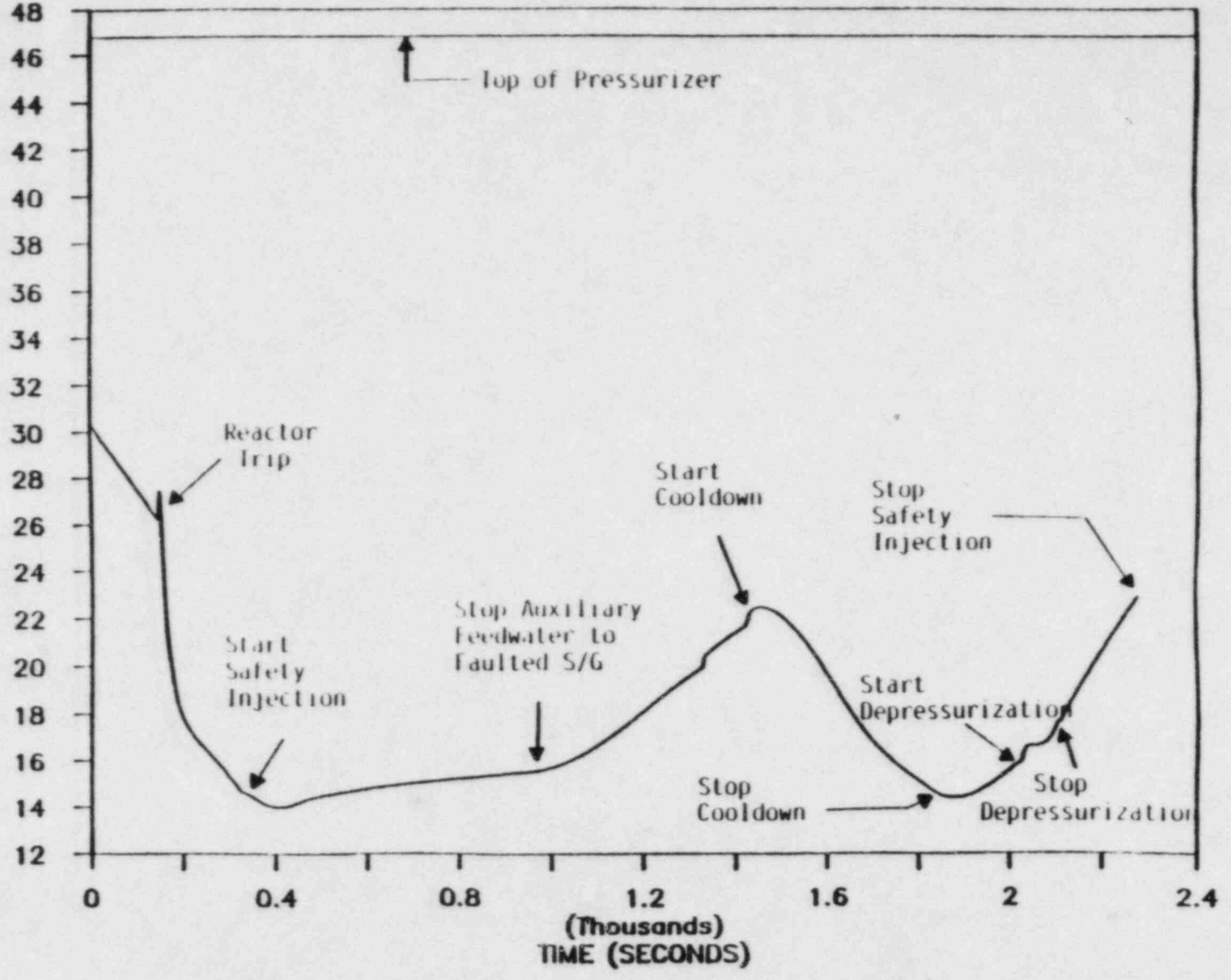


FIGURE 4-3 PRESSURIZER PORV FLOW
(Worst Case Potential Overfill)

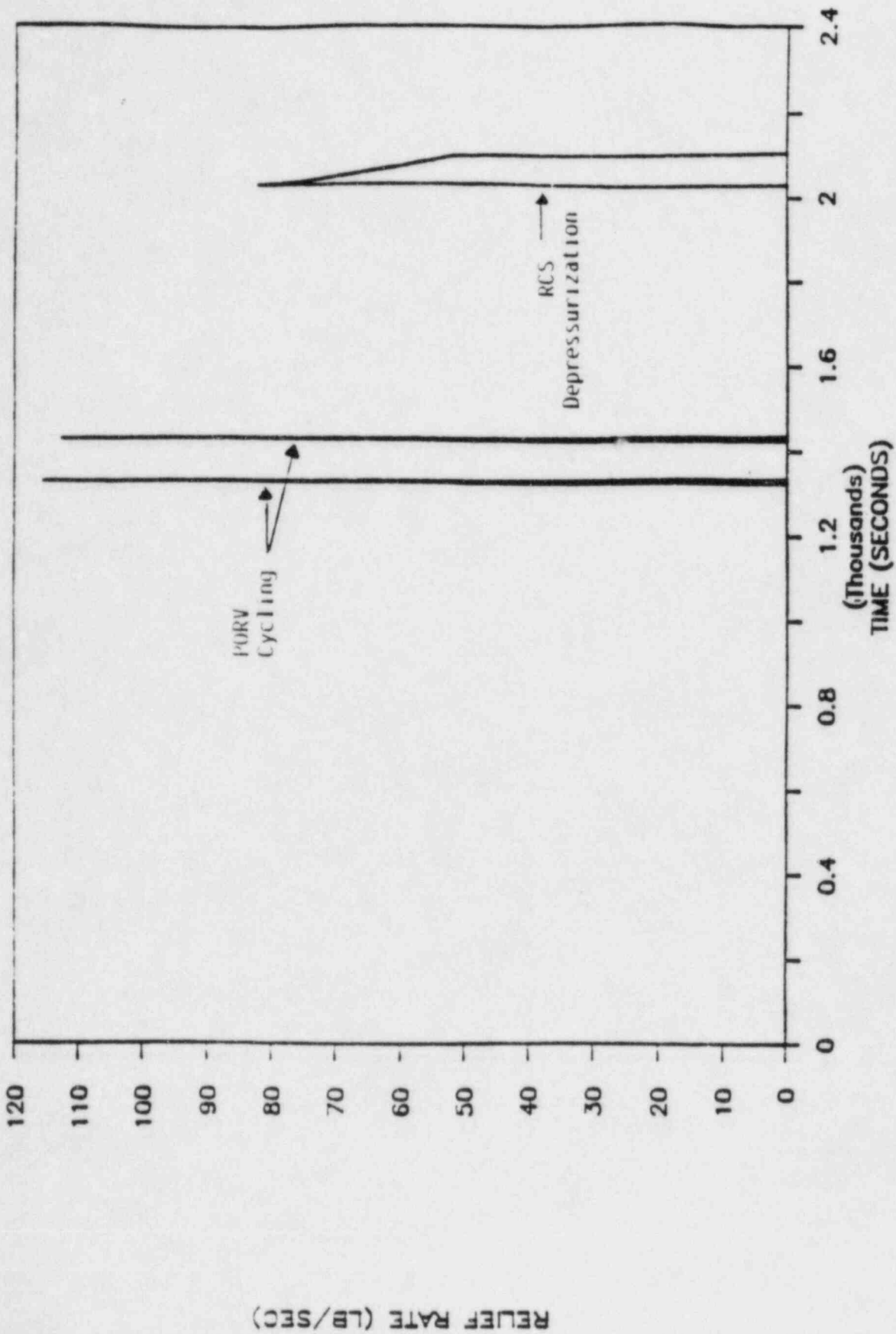


FIGURE 4-4 1-LOOP RCS TEMPERATURE
(Worst Case Potential Overfill)

4-13

RCS TEMPERATURE (F)

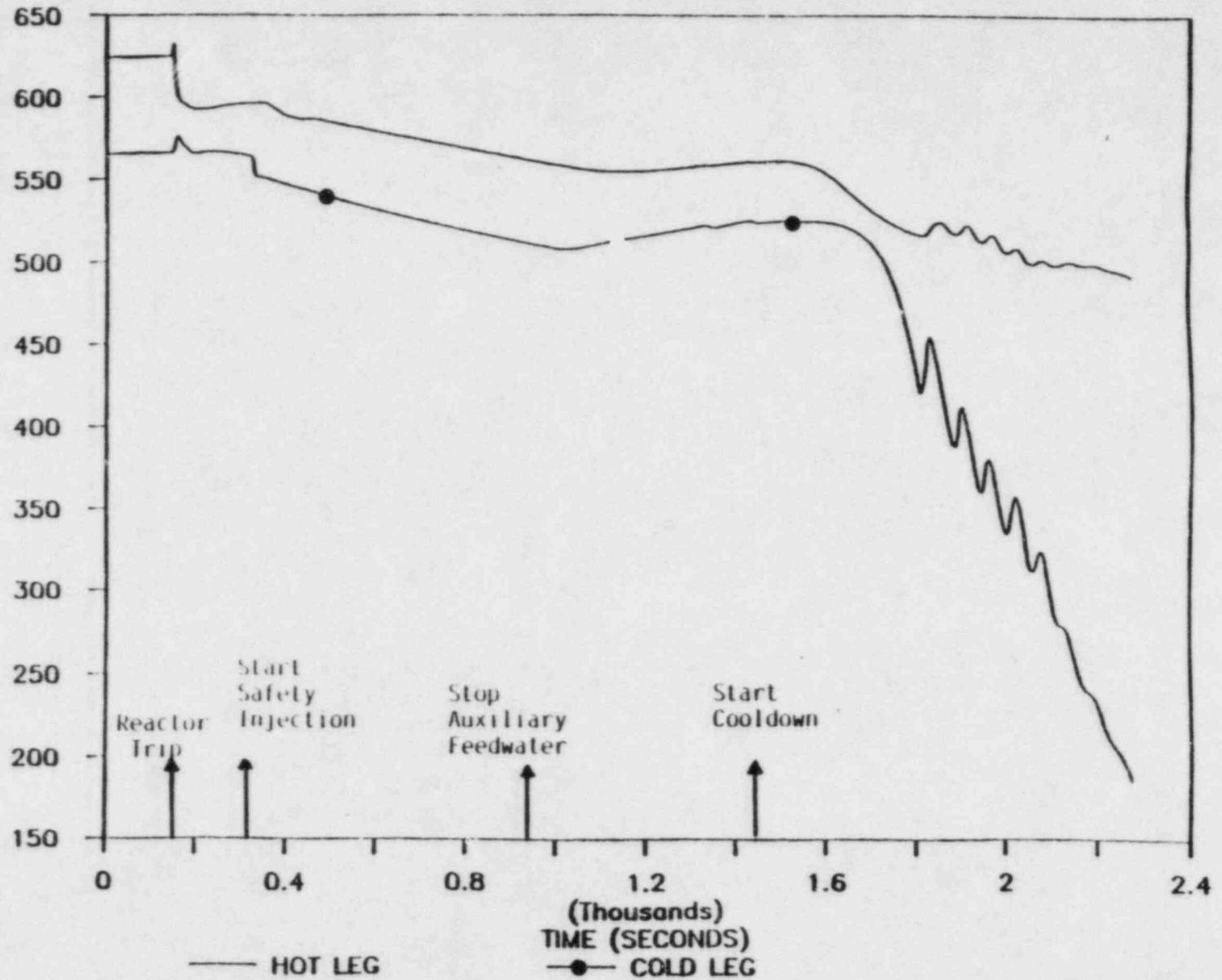


FIGURE 4-5 3-LOOP RCS TEMPERATURE
(Worst Case Potential Overfill)

4-14

RCS TEMPERATURE (F)

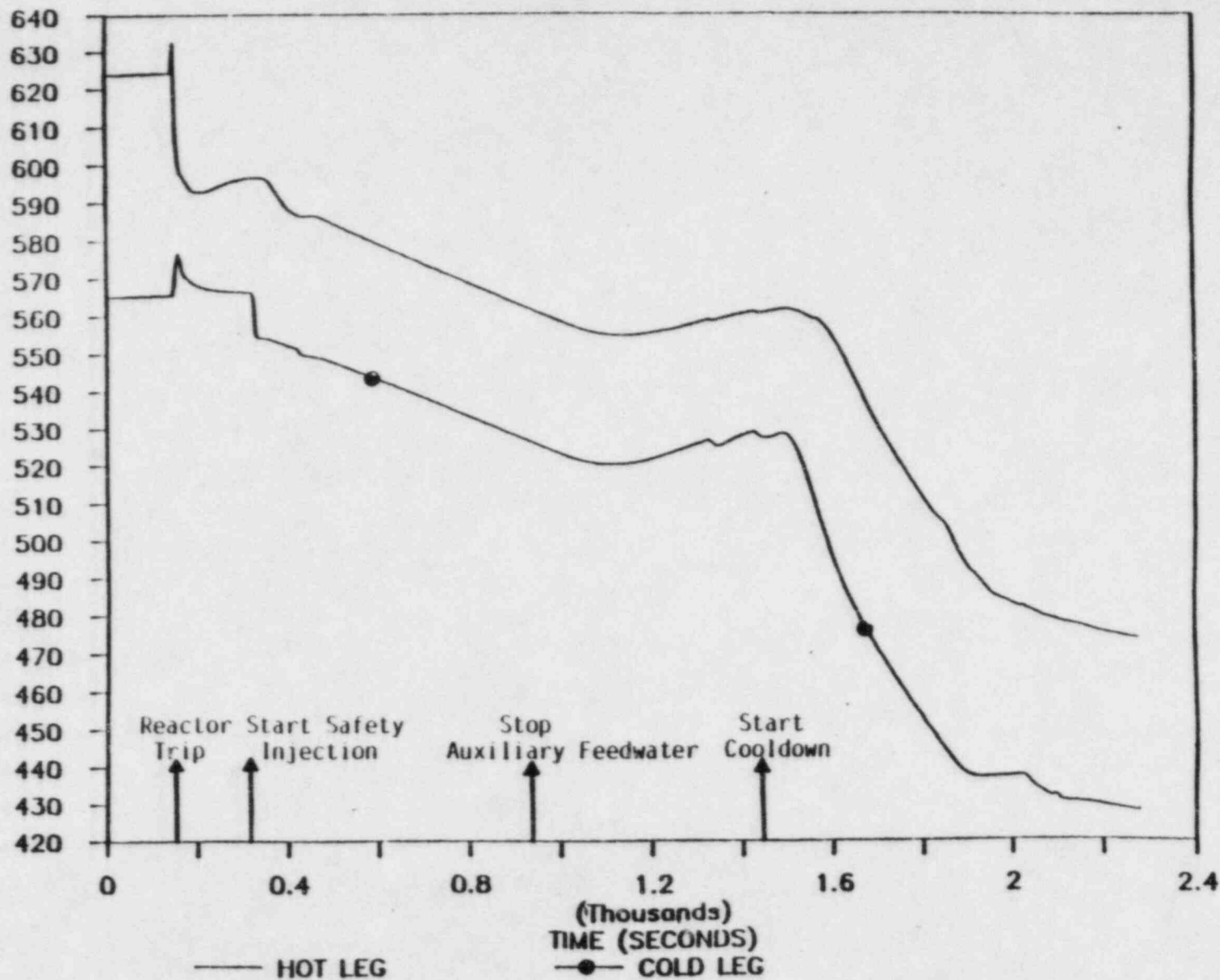


FIGURE 4-6 1-LOOP RCS FLOW
(Worst Case Potential Overfill)

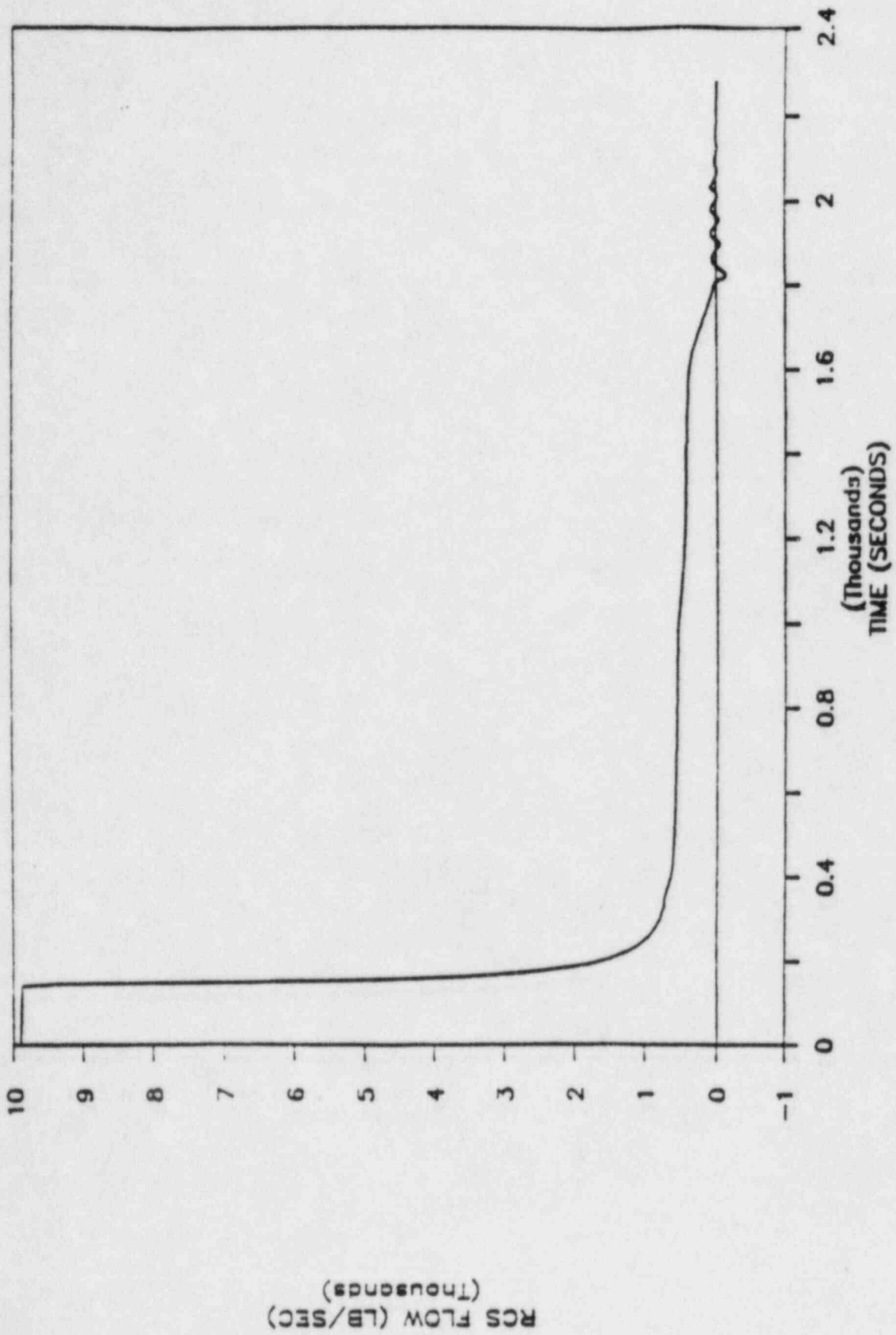


FIGURE 4-7 3-LOOP RCS FLOW
(Worst Case Potential Overfill)

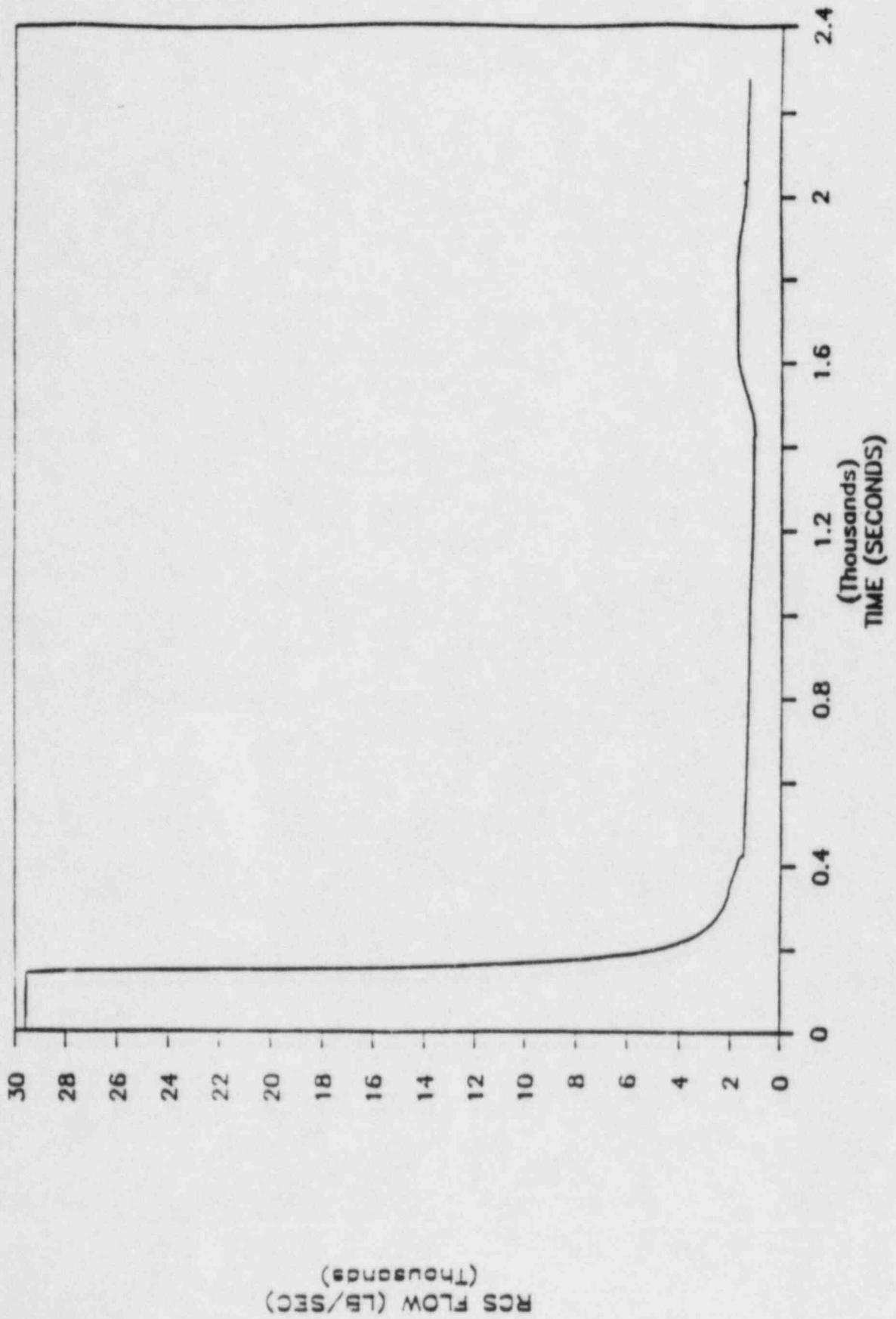


FIGURE 4-8 TOTAL BREAK FLOW IN FAULTED STEAM GENERATOR
(Worst Case Potential Overfill)

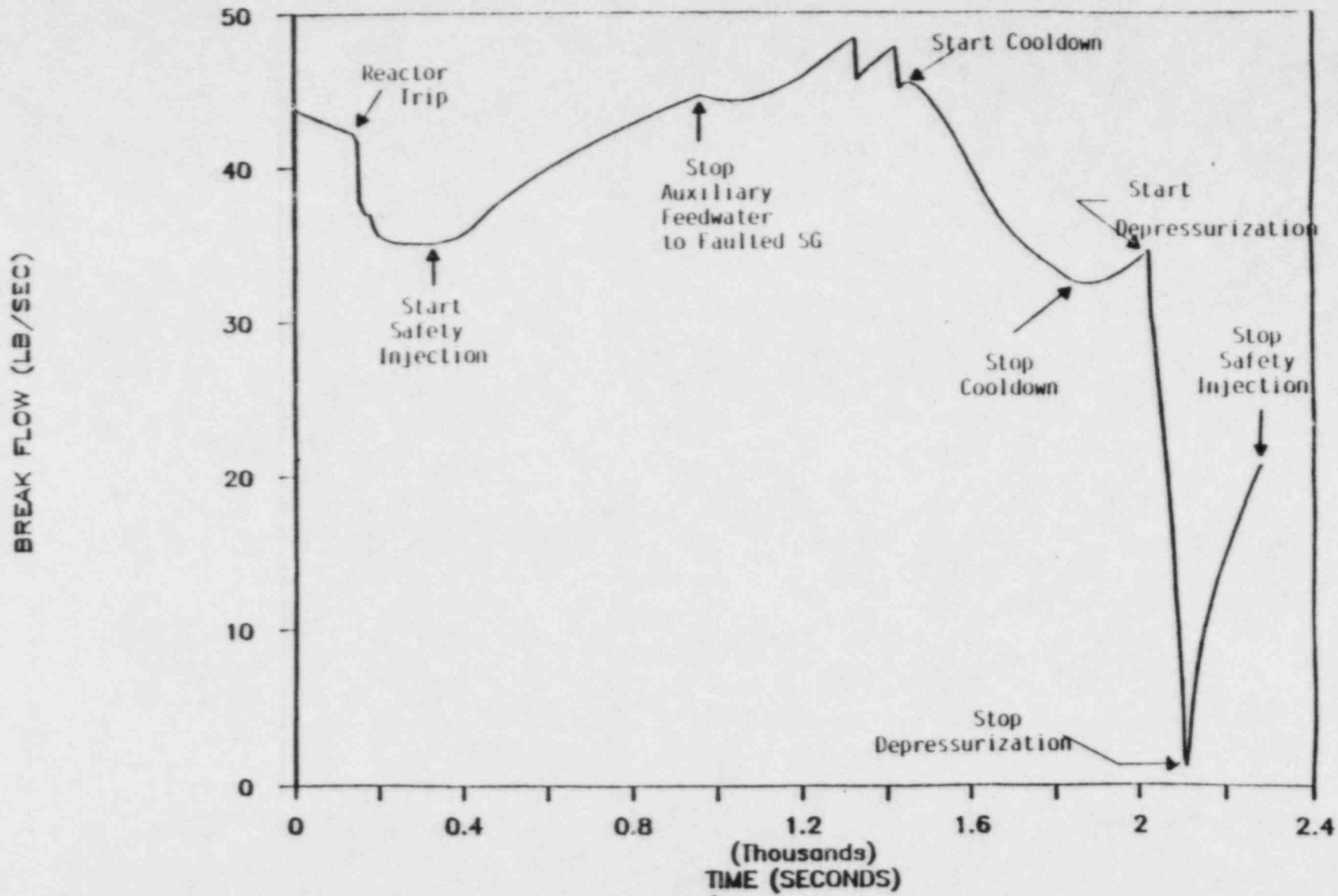


FIGURE 4-9 STEAM GENERATOR PRESSURE
(Wors' Case Potential, Overfill)

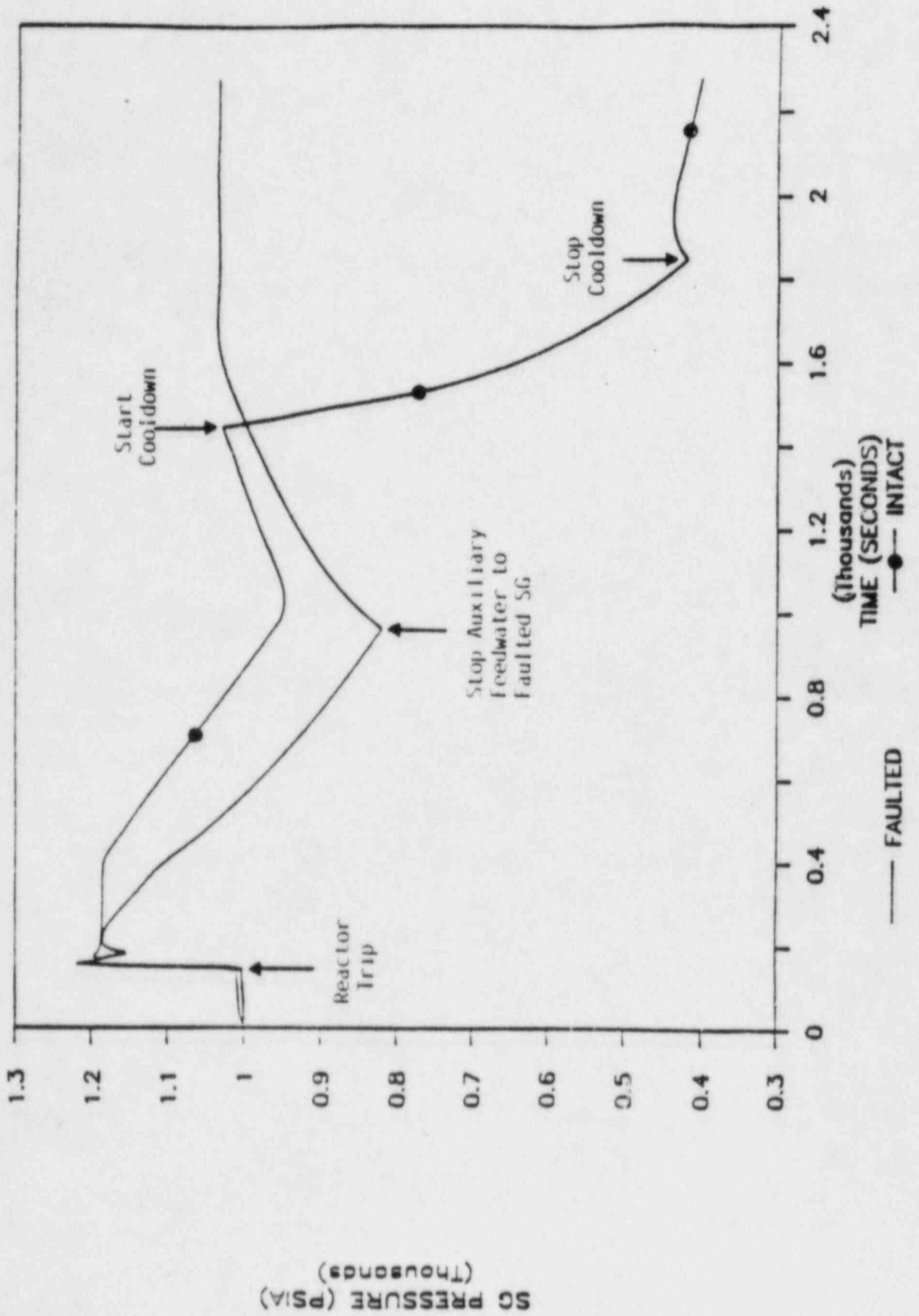


FIGURE 4-10 STEAM GENERATOR TEMPERATURE
(Worst Case Potential, Overfill)

SG TEMPERATURE (F)

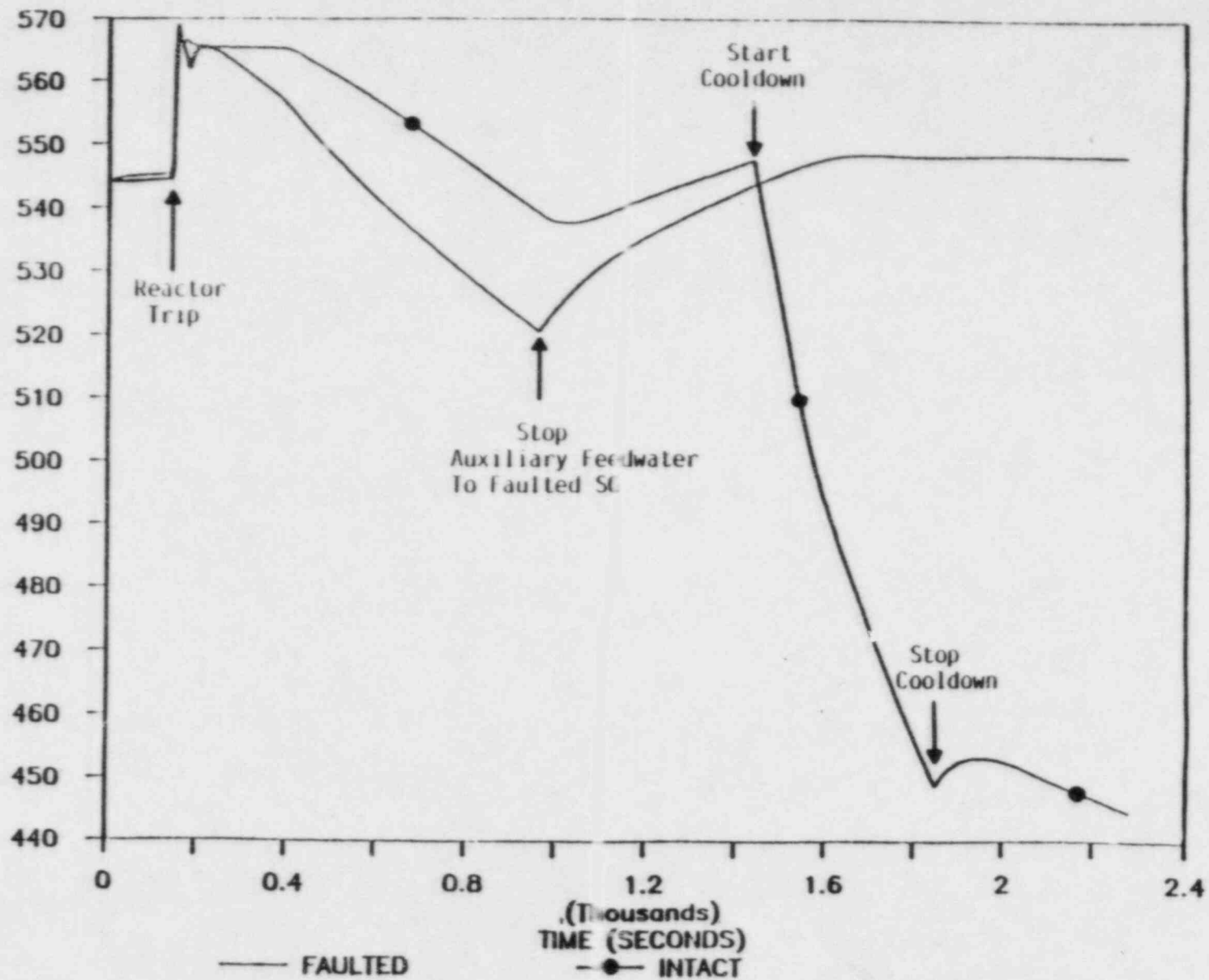


FIGURE 4-11 MIXTURE VOLUME IN FAULTED STEAM GENERATOR
(Worst Case Potential Overfill)

4-20

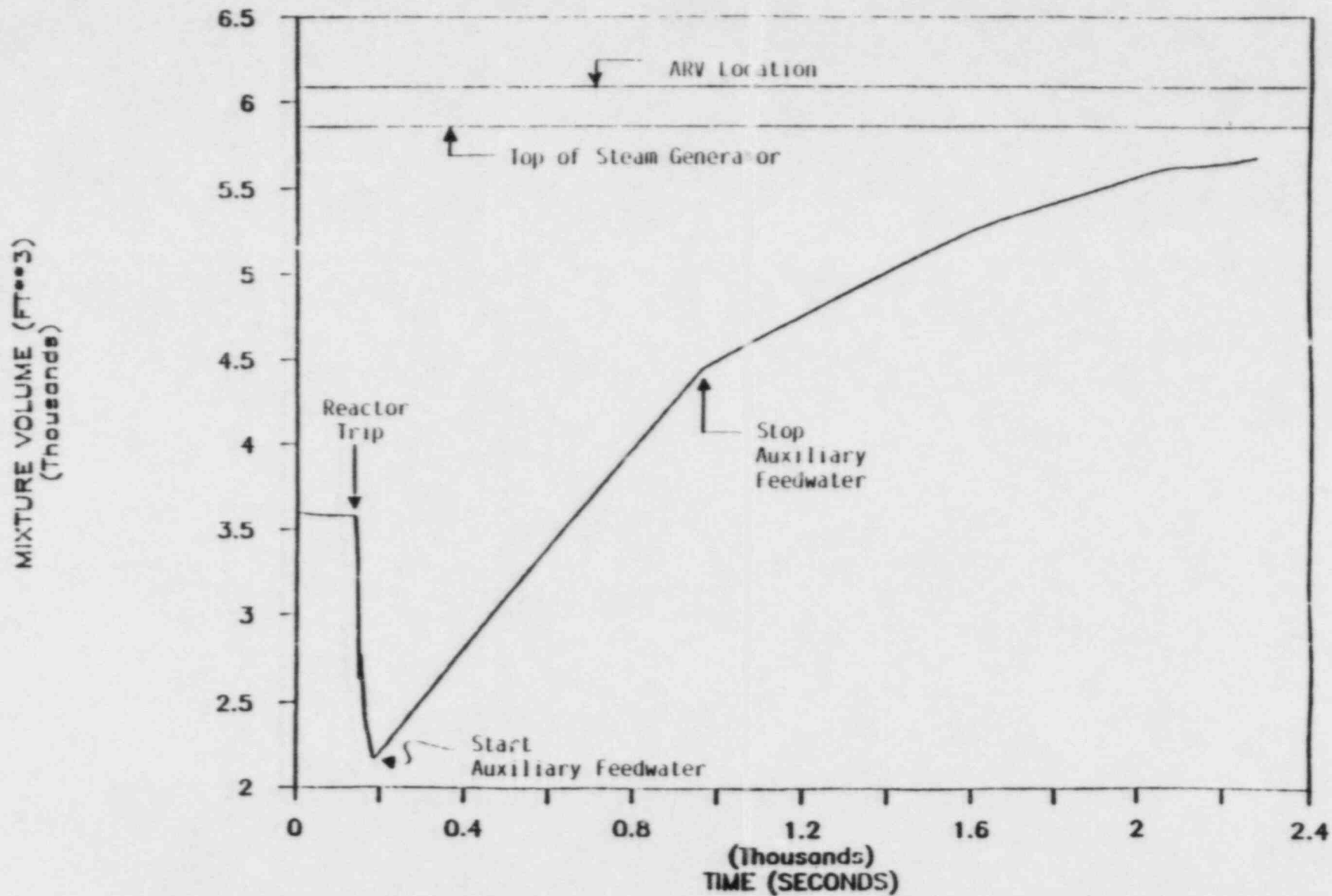


FIGURE 4-12 STEAM FLOW IN FAULTED STEAM GENERATOR
(Worst Case Potential Overfill)

4-21

STEAM FLOW (LB/SEC)
(Thousands)

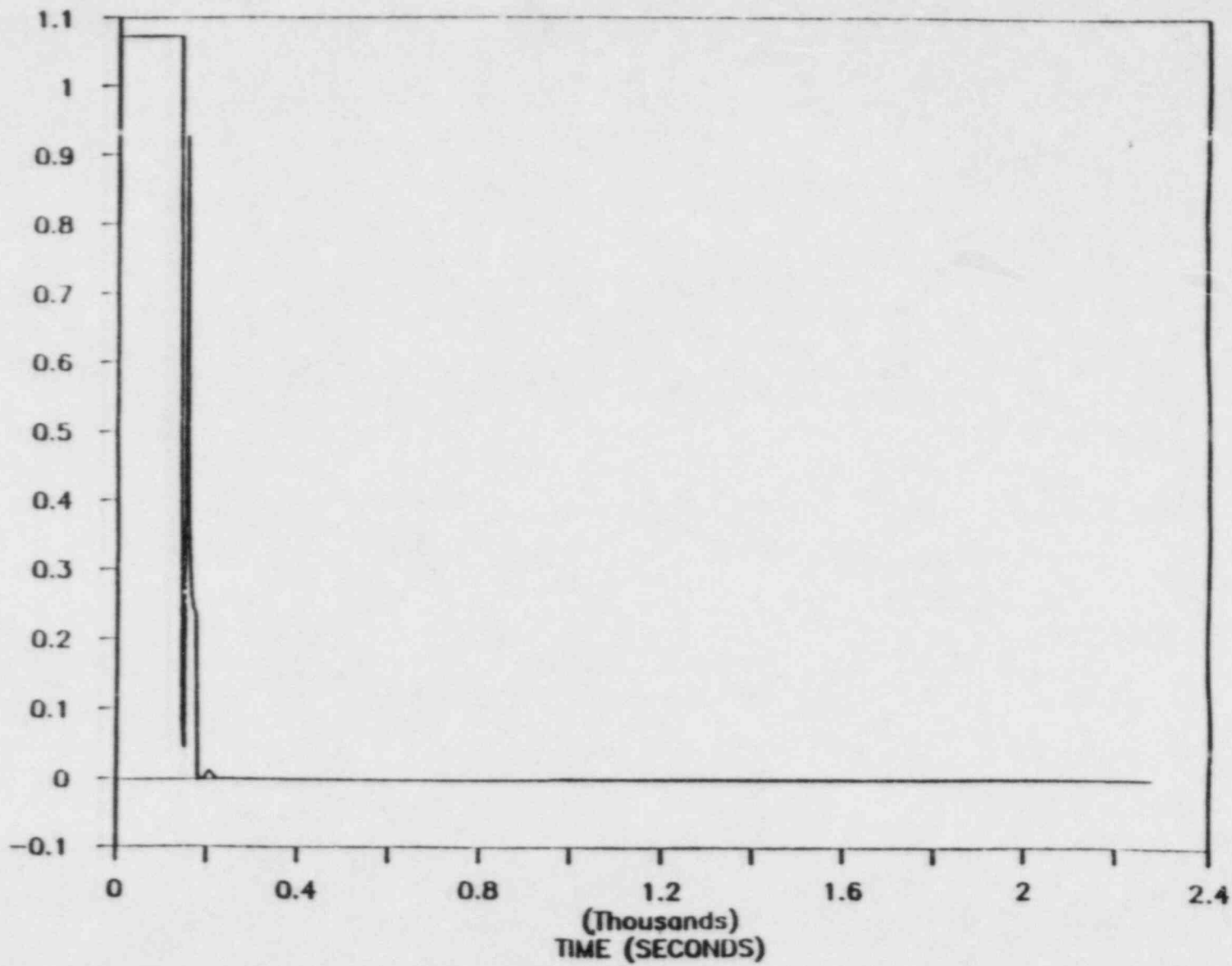


FIGURE 4-13 STEAM FLOW IN INTACT STEAM GENERATORS
(Worst Case Potential Overfill)

4-22

STEAM FLOW (LB/SEC)
(Thousands)

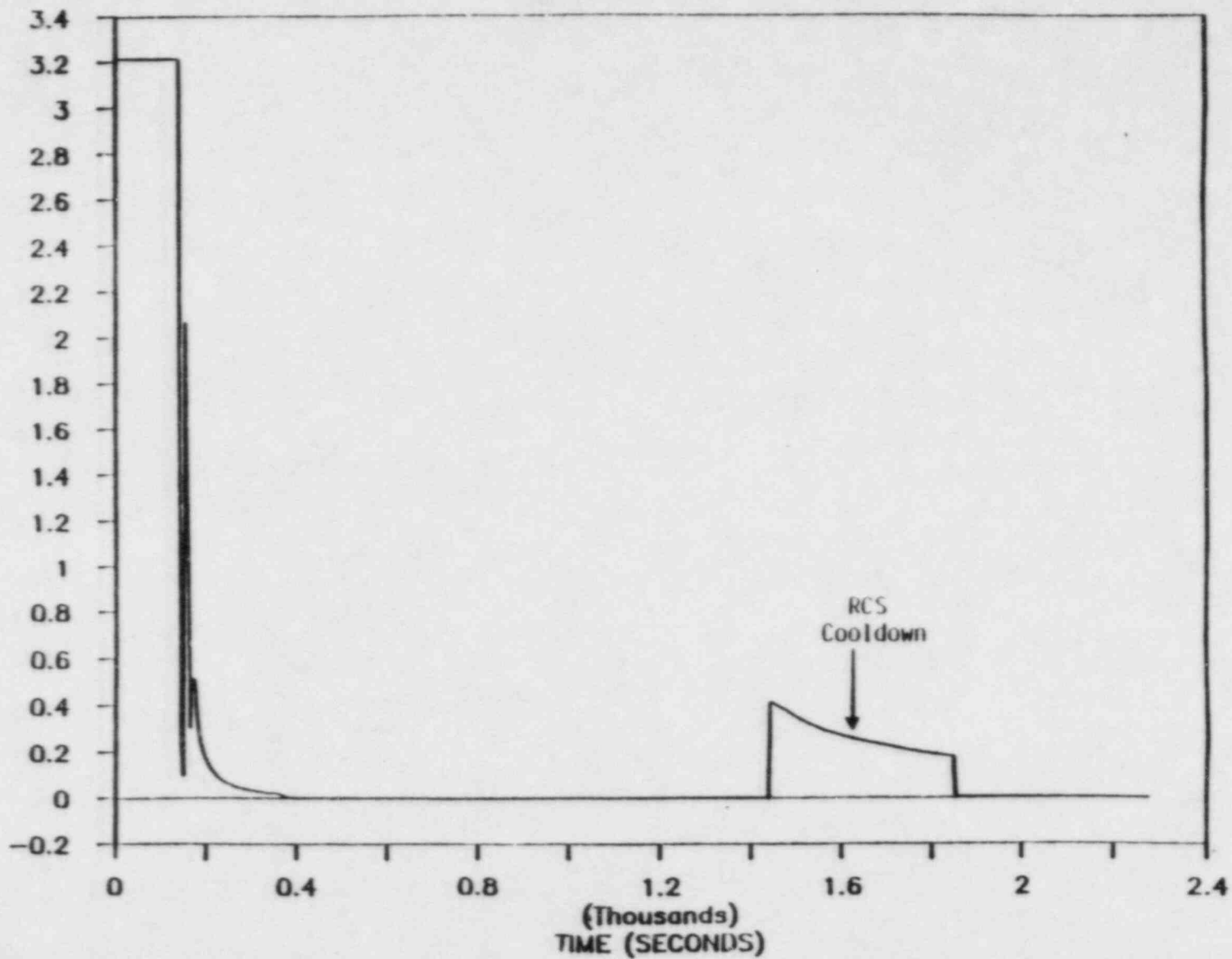


FIGURE 4-14 AFW FLOW AND INDICATED NARROW RANGE LEVEL (NR)
IN FAULTED STEAM GENERATOR
(Worst Case Potential Overfill)

4-23

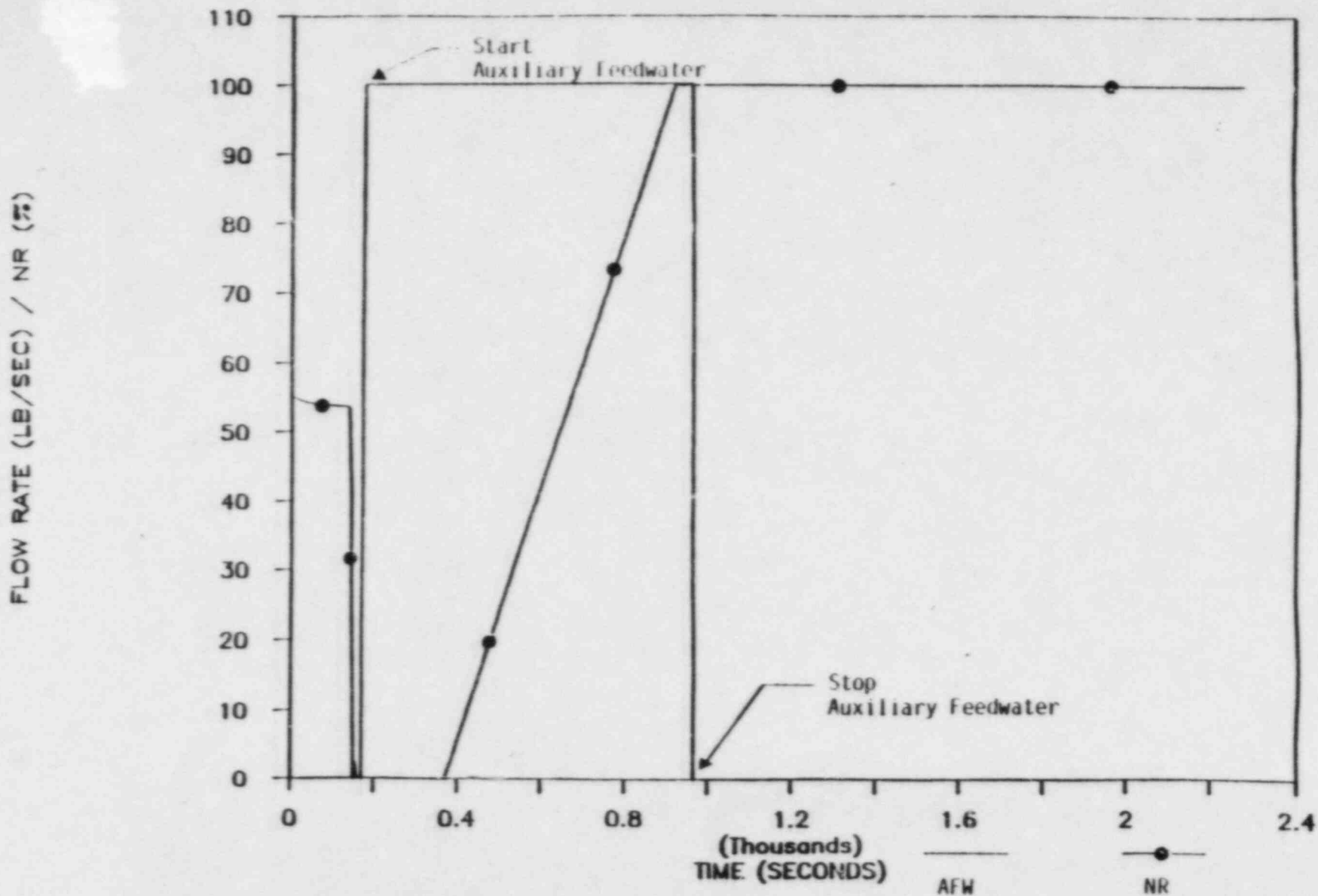


FIGURE 4-15 AFW AS A FUNCTION OF NR IN INTACT STEAM GENERATORS
(Worst Case Potential Overflow)

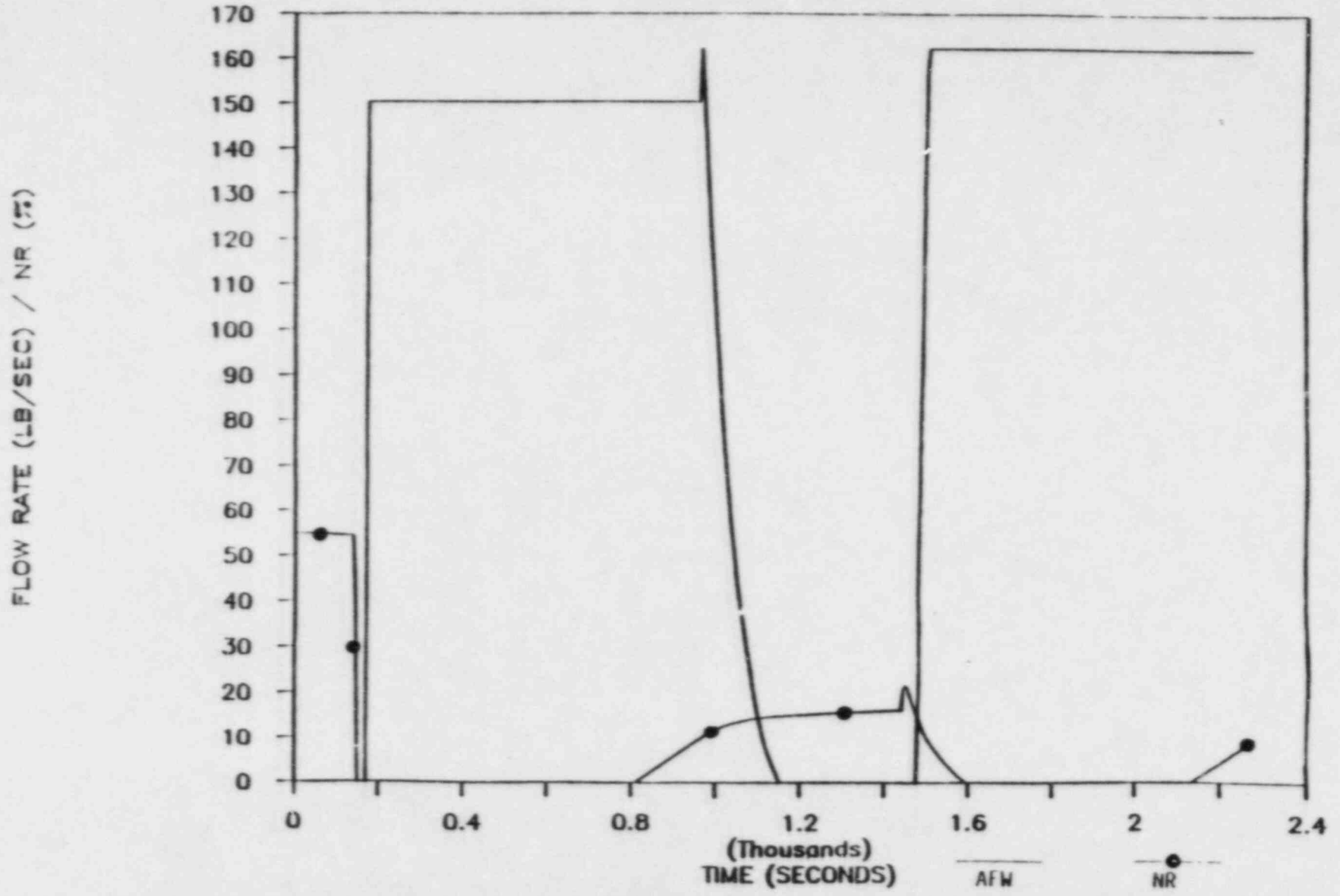
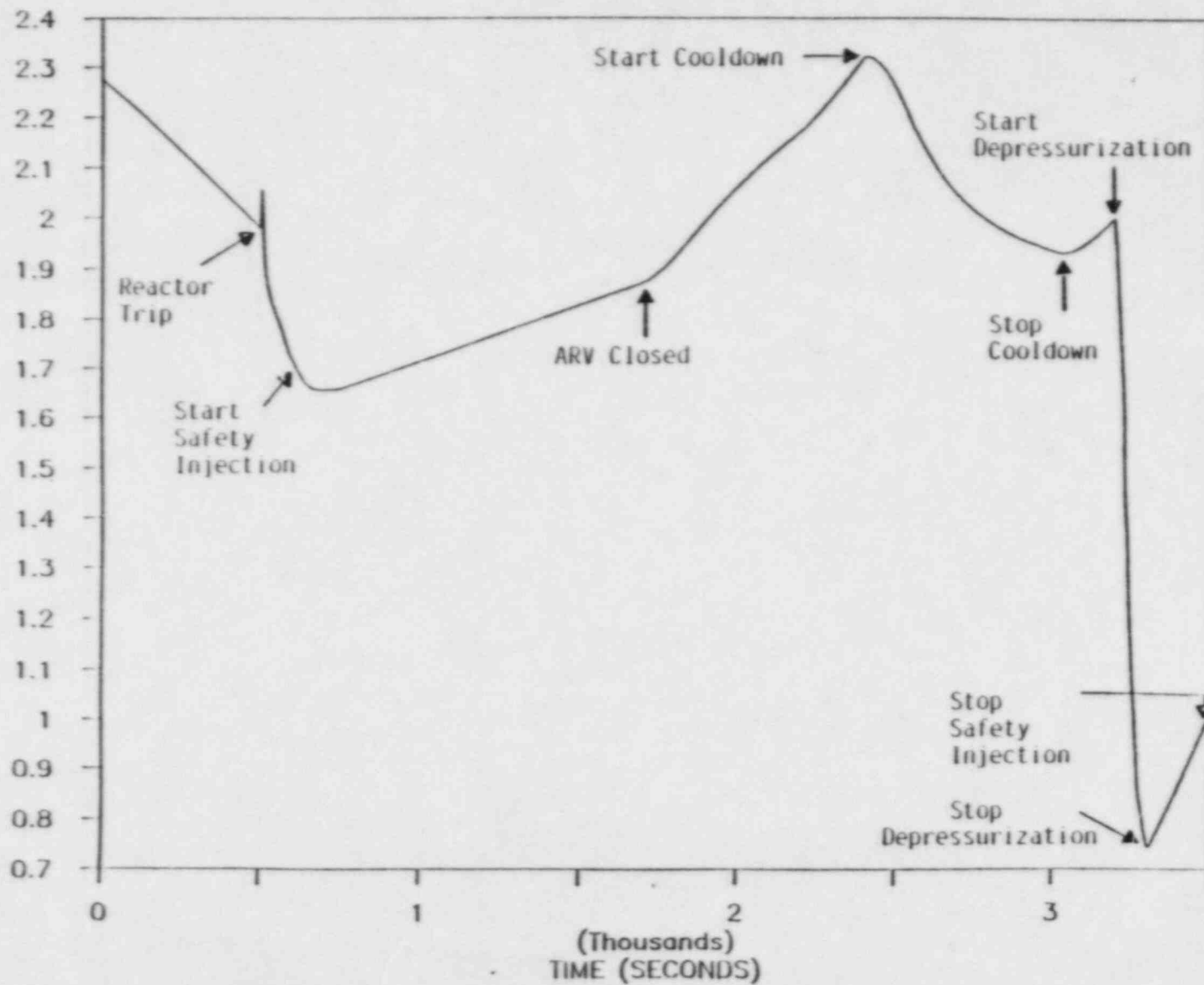
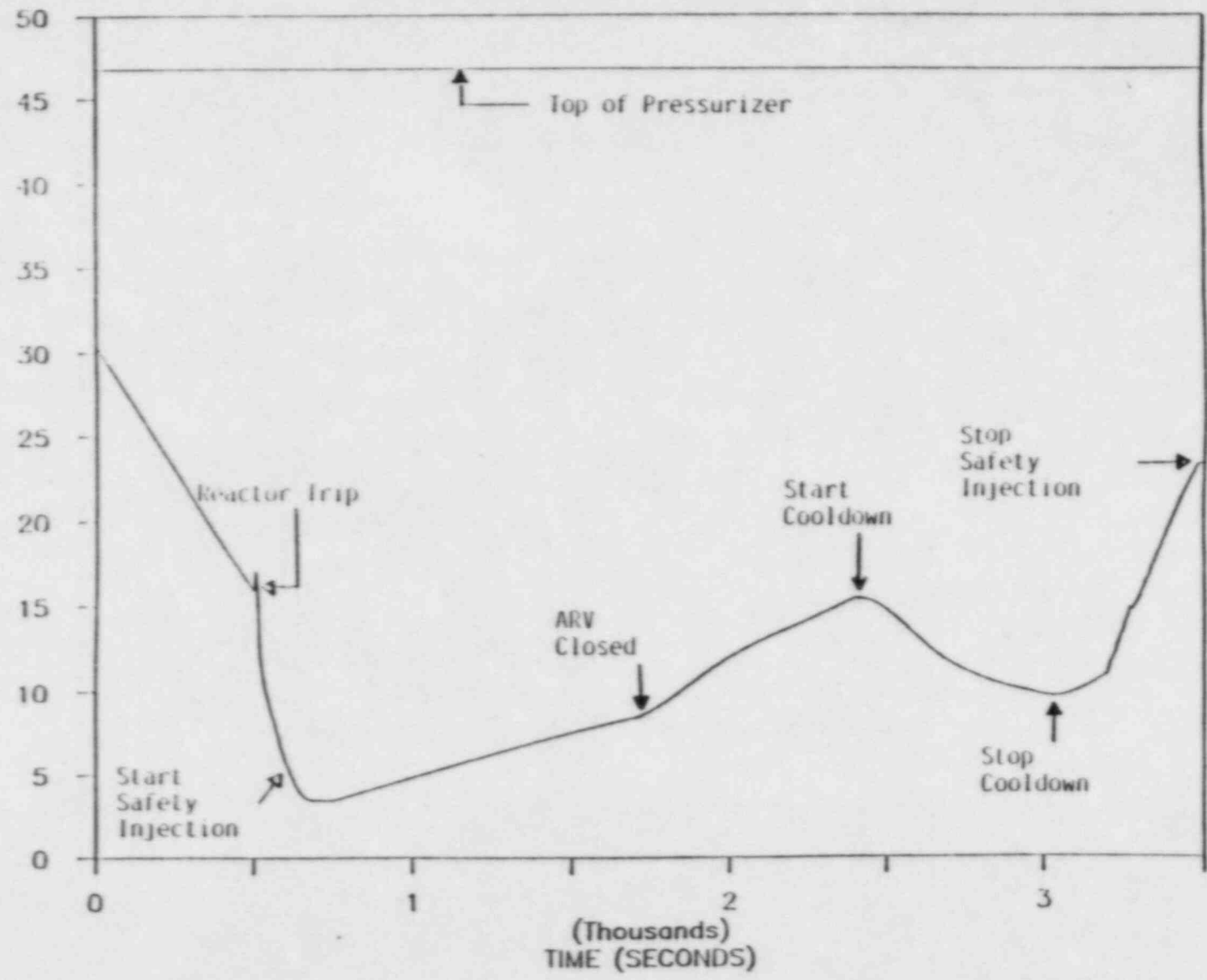


FIGURE 4-16 REACTOR COOLANT SYSTEM PRESSURE (WORST CASE DOSE)



(MPa) (PRESSURE)
RCS PRESSURE

FIGURE 4-17 PRESSURIZER WATER LEVEL
(WORST CASE DOSE)



4-26

WATER LEVEL (FEET)

FIGURE 4-18 PRESSURIZER PORV FLOW
(WORST CASE DOSE)

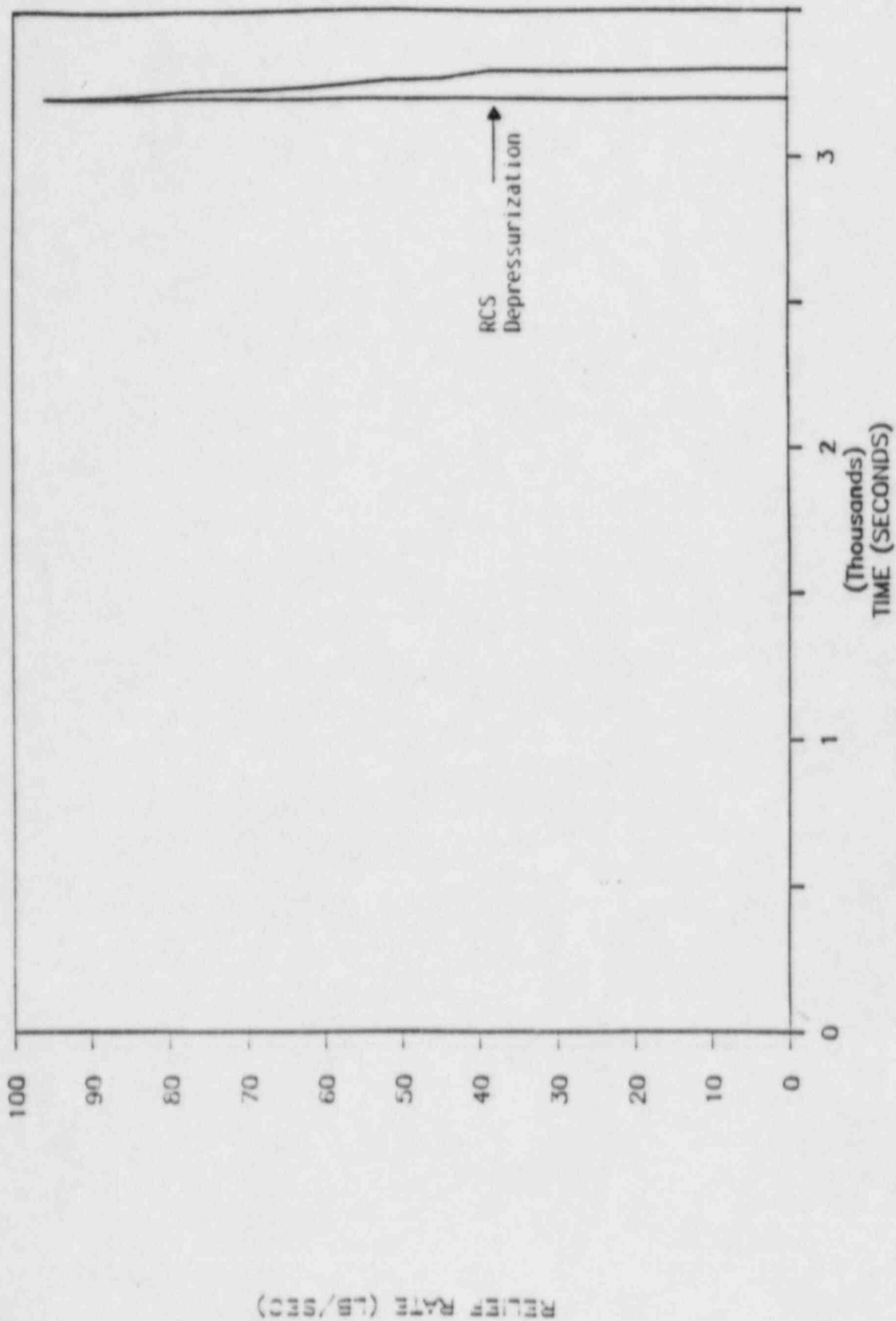
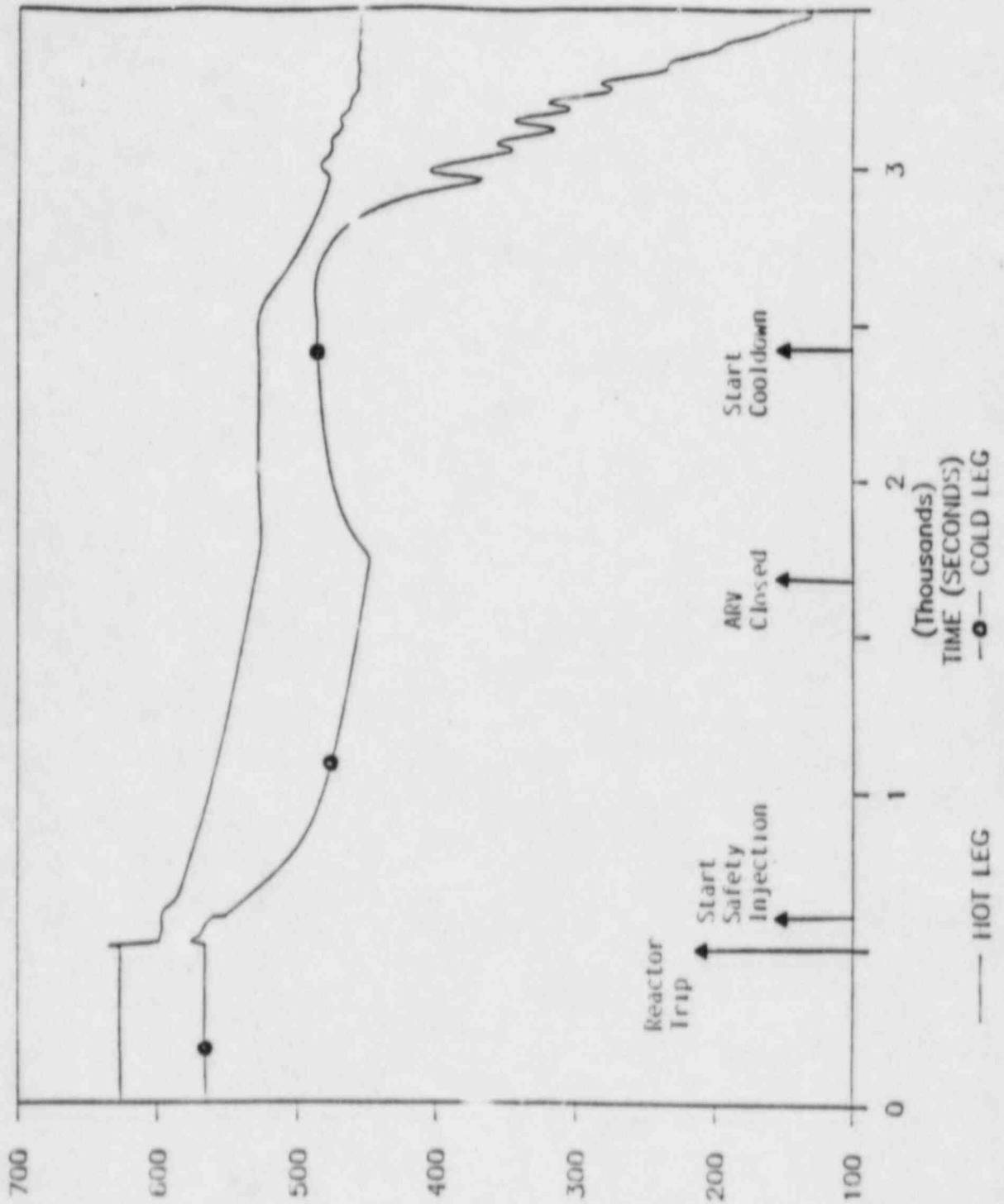
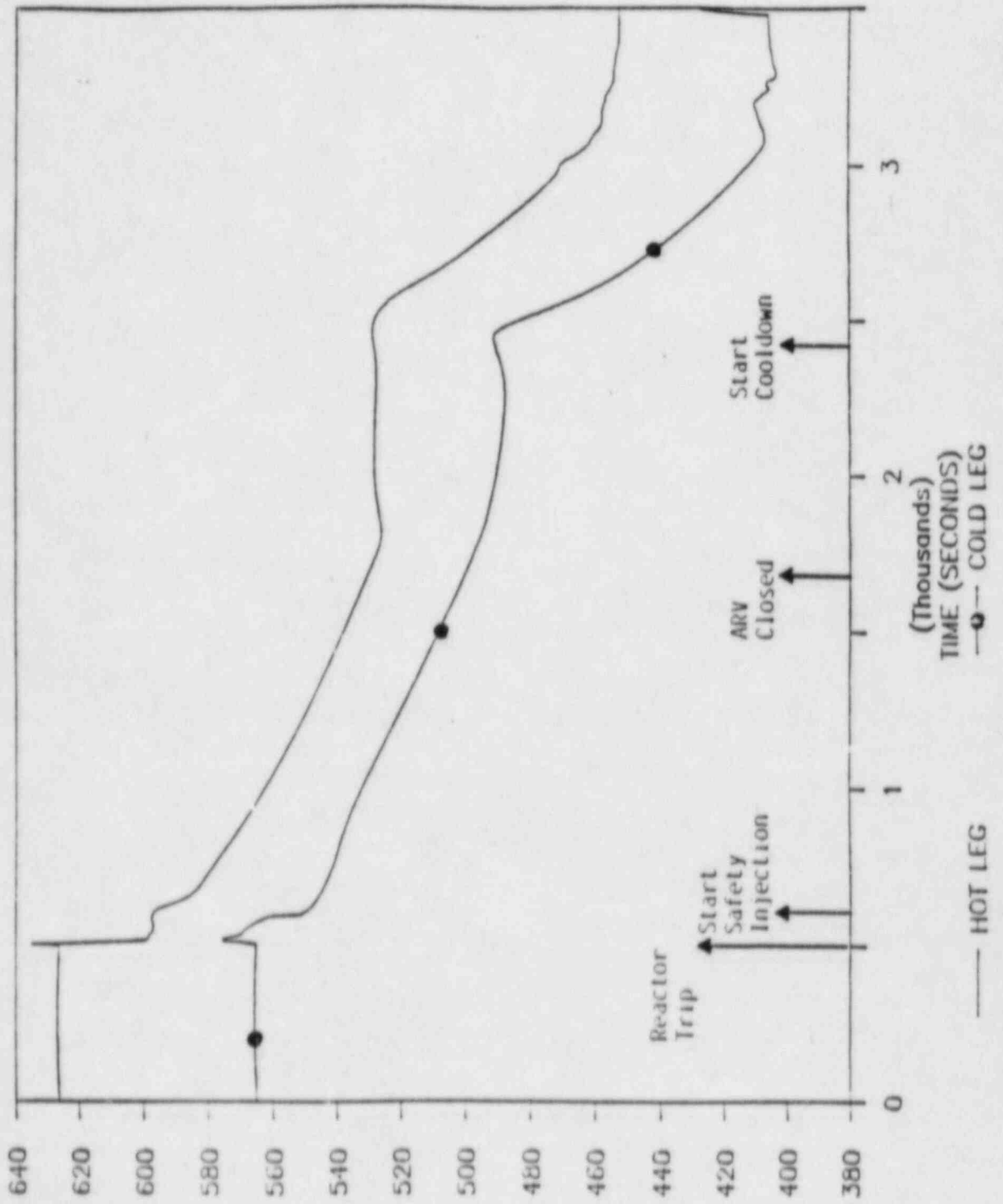


FIGURE 4-19 1-LOOP RCS TEMPERATURE
(WORST CASE DOSE)



(b) REACTOR COOLANT SYSTEM

FIGURE 4-20 3-LOOP RCS TEMPERATURE
(WORST CASE DOSE)



(L) 4-20 3-LOOP RCS TEMPERATURE

FIGURE 4-21 1-LOOP RCS FLOW
(WORST CASE DOSE)

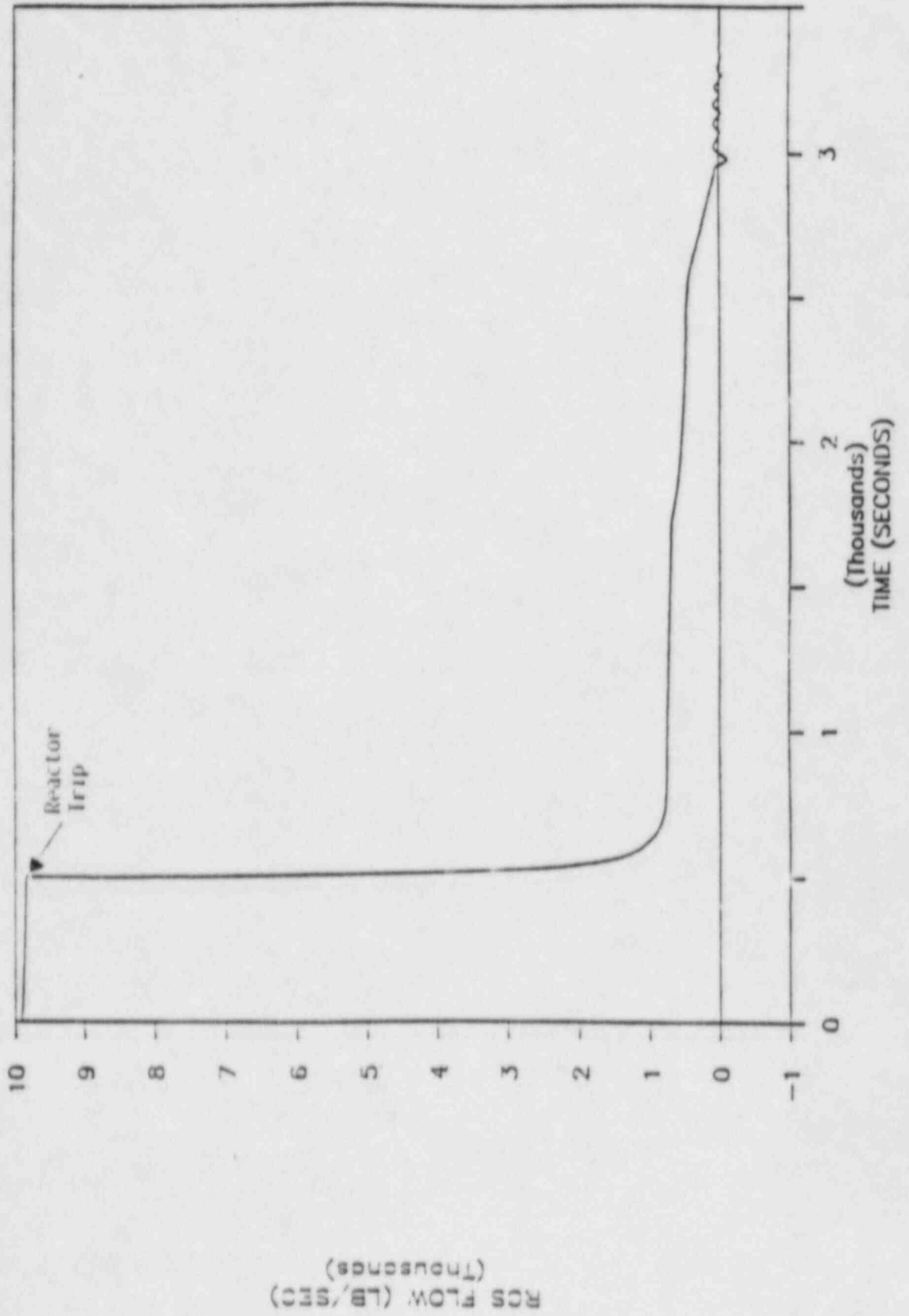


FIGURE 4-22 3-LOOP RCS FLOW
(WORST CASE DOSE)

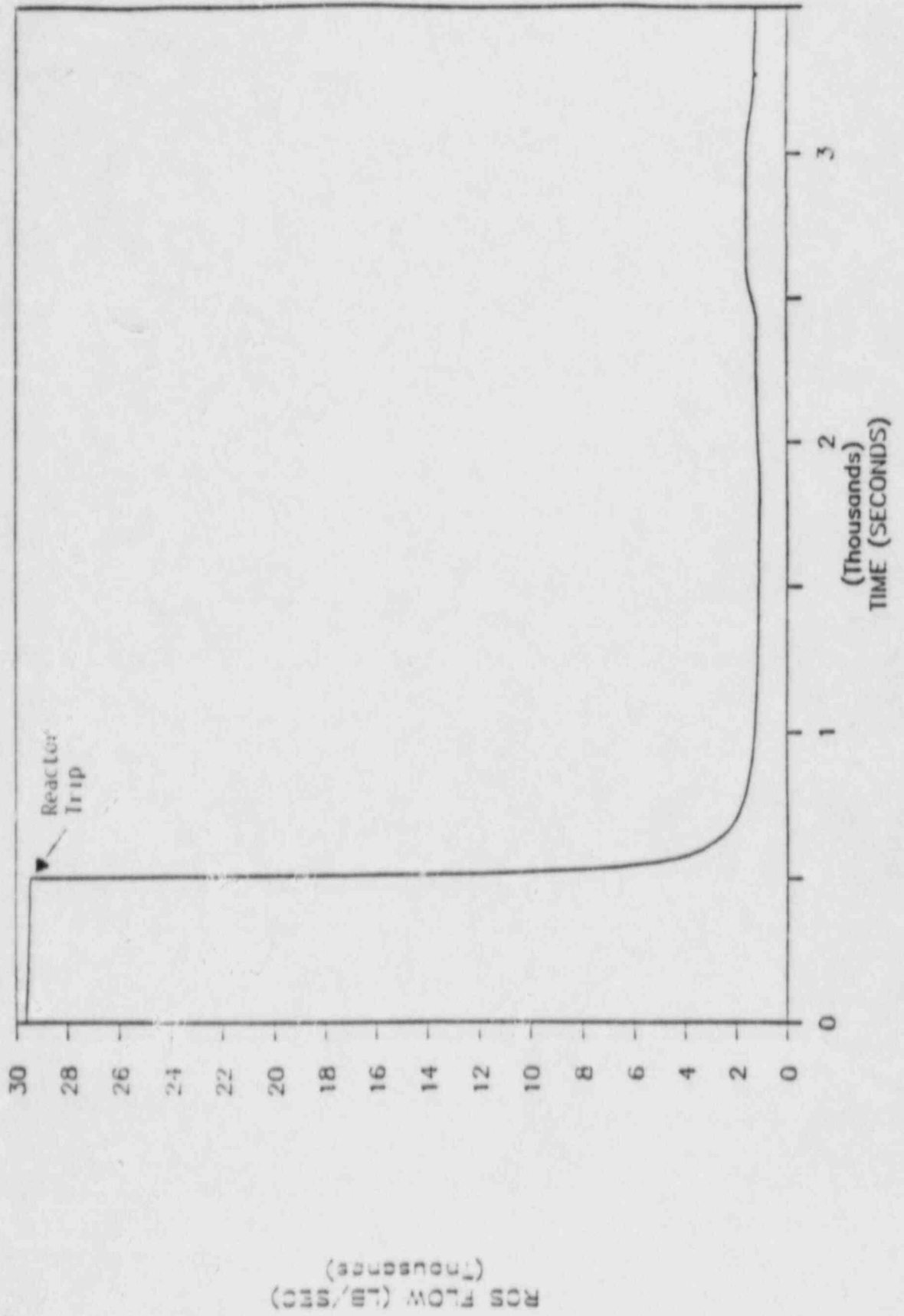
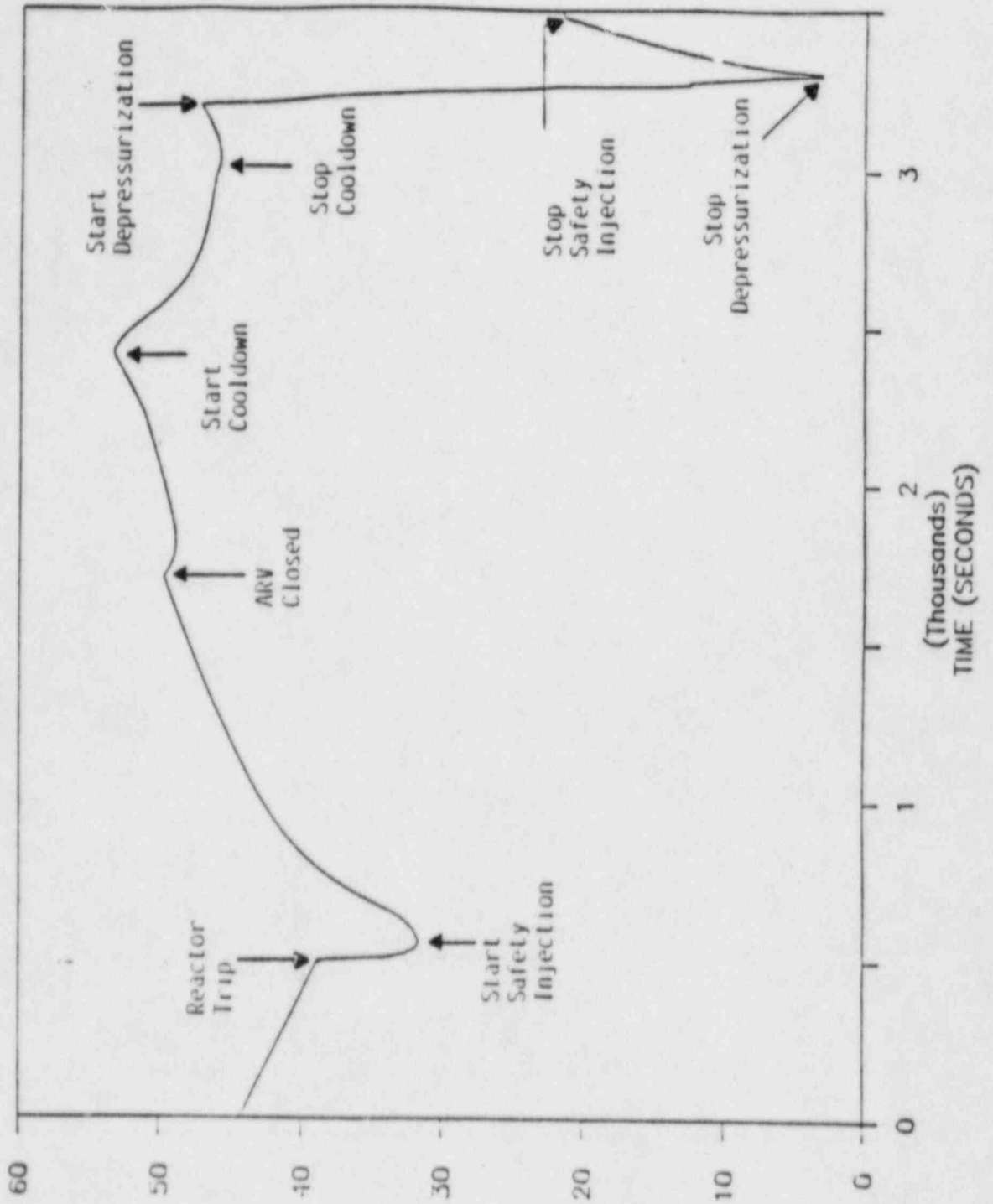


FIGURE 4-23 TOTAL BREAK FLOW IN FAULTED STEAM GENERATOR
(WORST CASE DOSE)



(GPM) (10⁶)

FIGURE 4-24 STEAM GENERATOR PRESSURE
(WORST CASE DOSE)

(spuonouT)
S S E R P P (S I S)
4-33

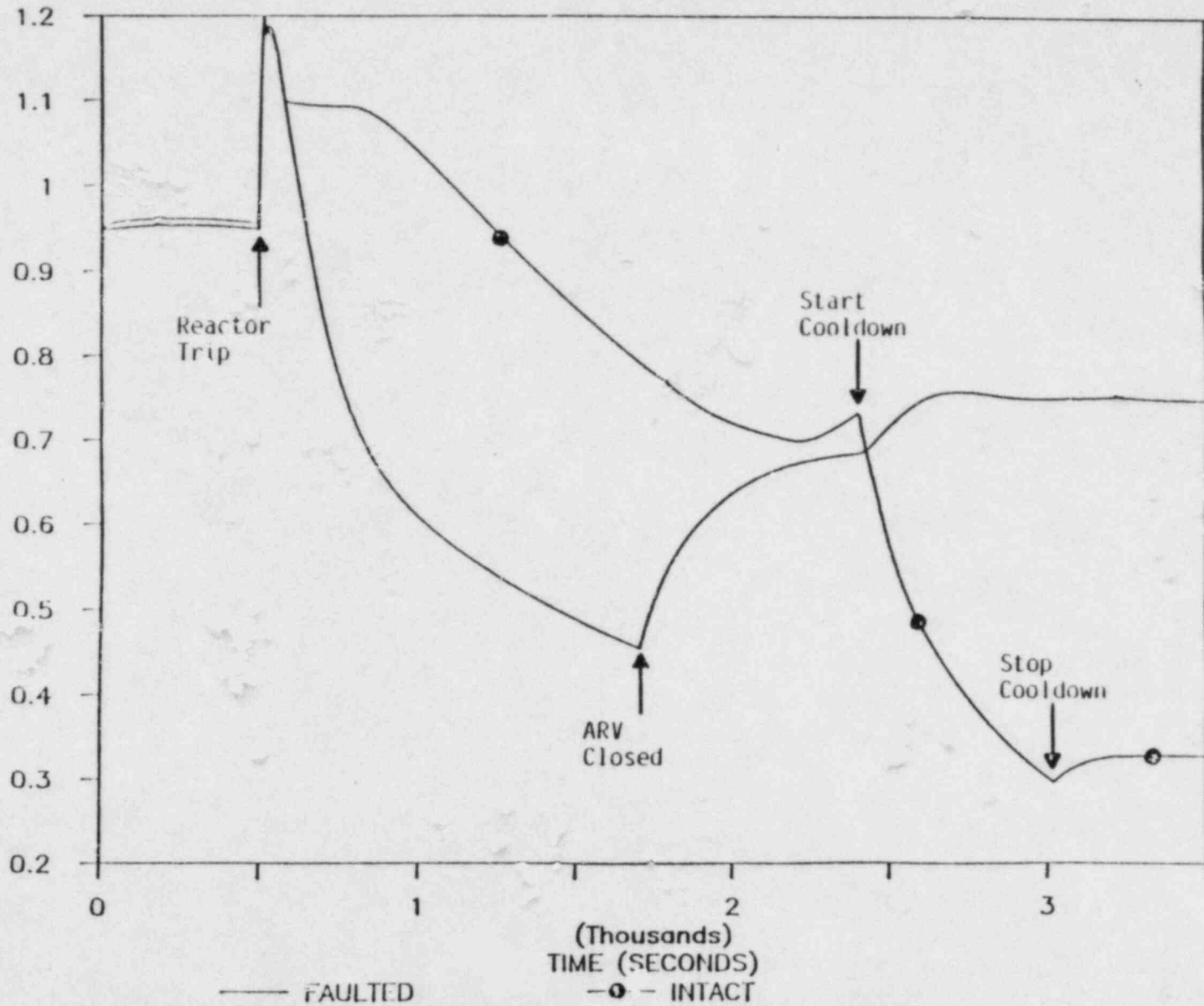


FIGURE 4-25 STEAM GENERATOR TEMPERATURE
(WORST CASE DOSE)

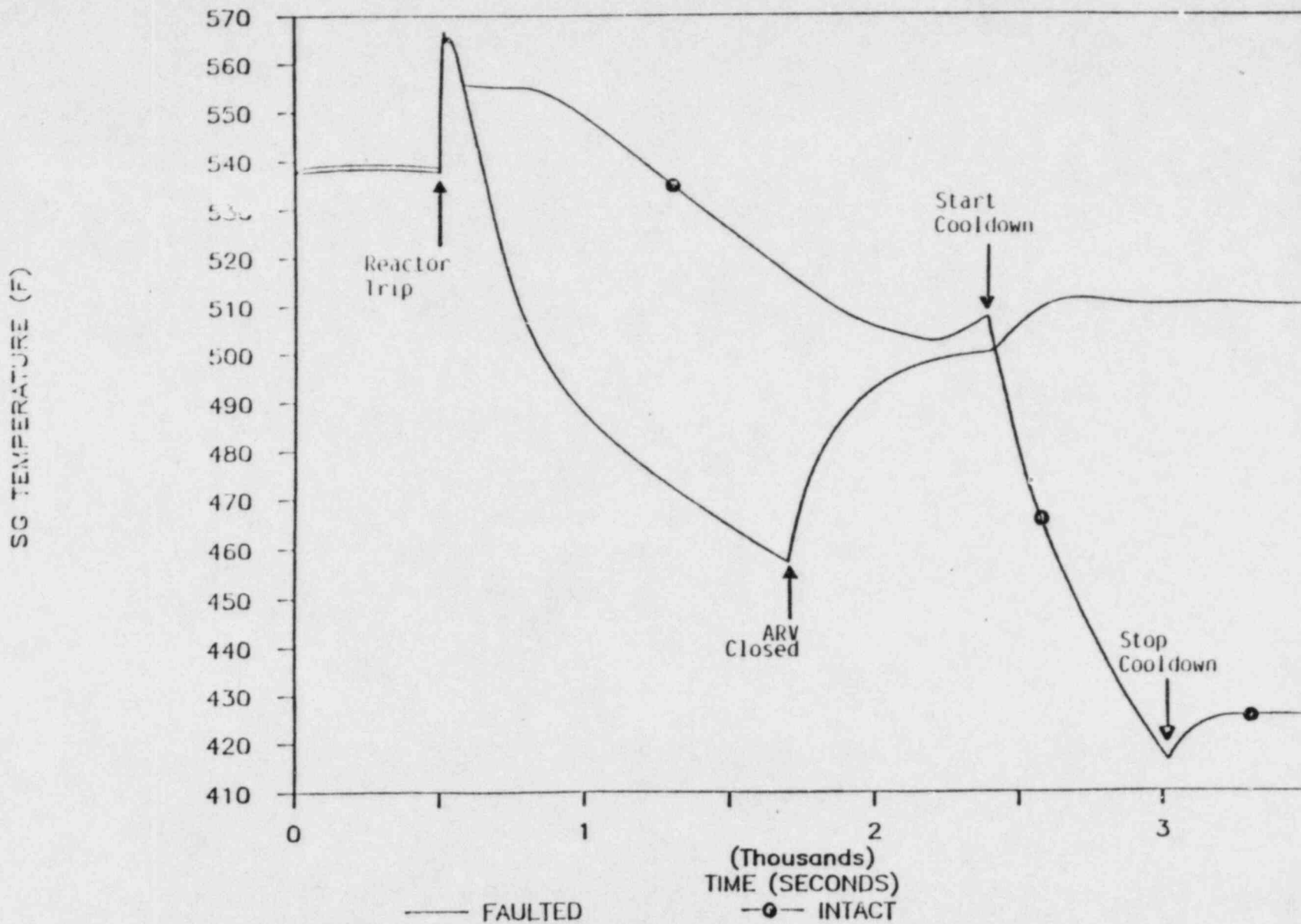


FIGURE 4-26 MIXTURE VOLUME IN FAULTED STEAM GENERATOR
(WORST CASE DOSE)

MIXTURE VOLUME (FT³)
(Thousands)

4-35

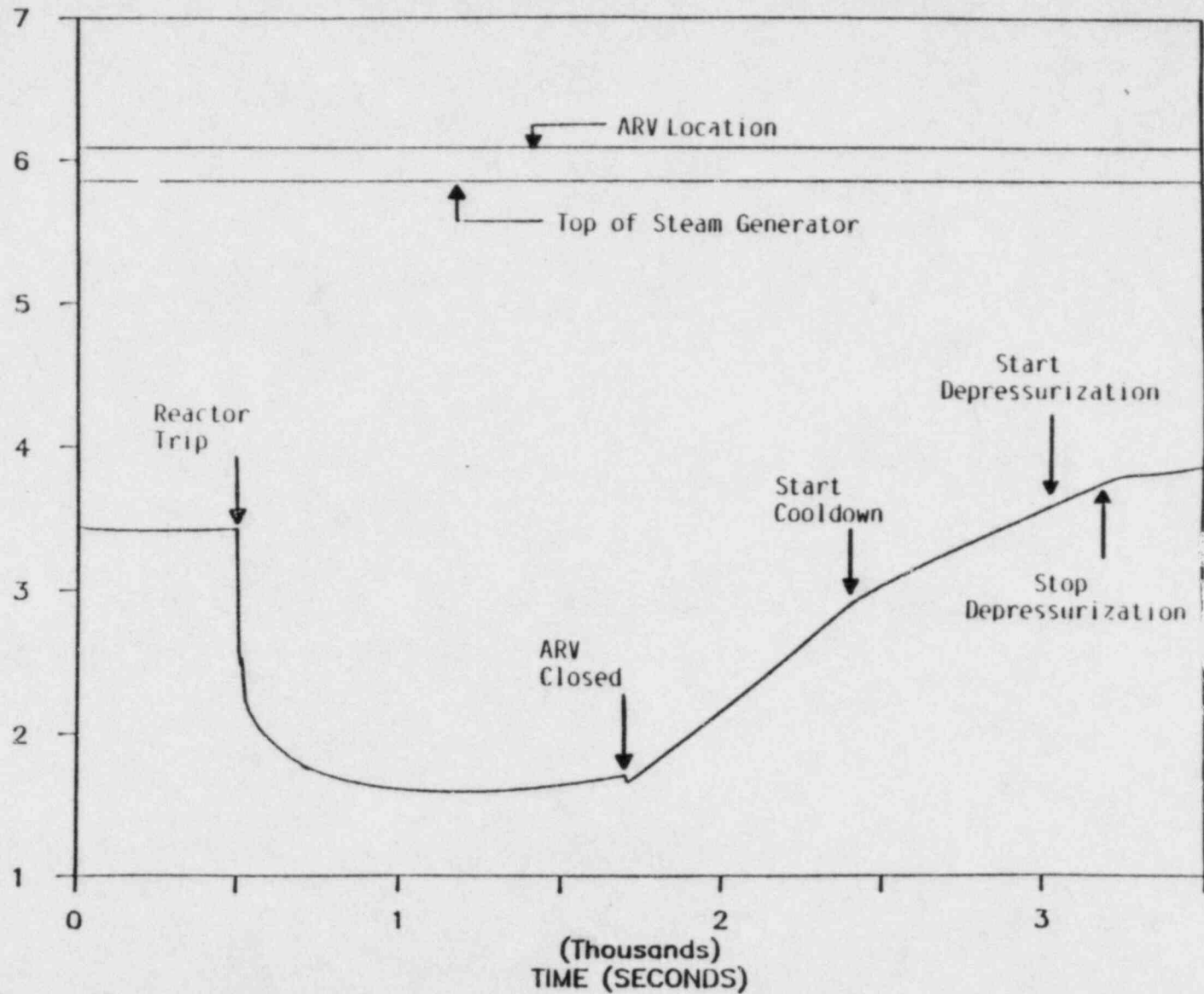


FIGURE 4-27 STEAM FLOW IN FAULTED STEAM GENERATOR
(WORST CASE DOSE)

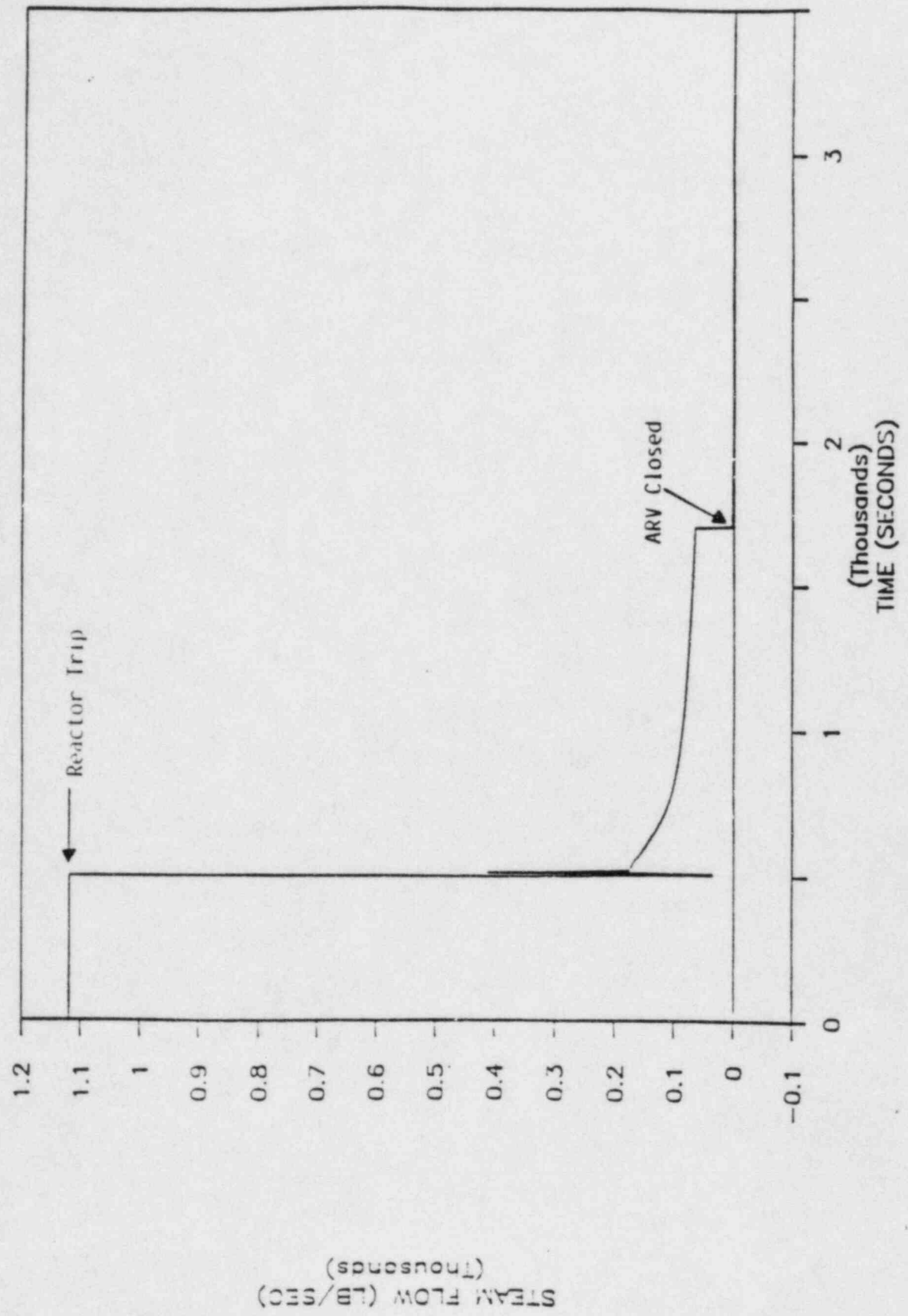


FIGURE 4-28 STEAM FLOW IN INTACT STEAM GENERATORS
(WORST CASE DOSE)

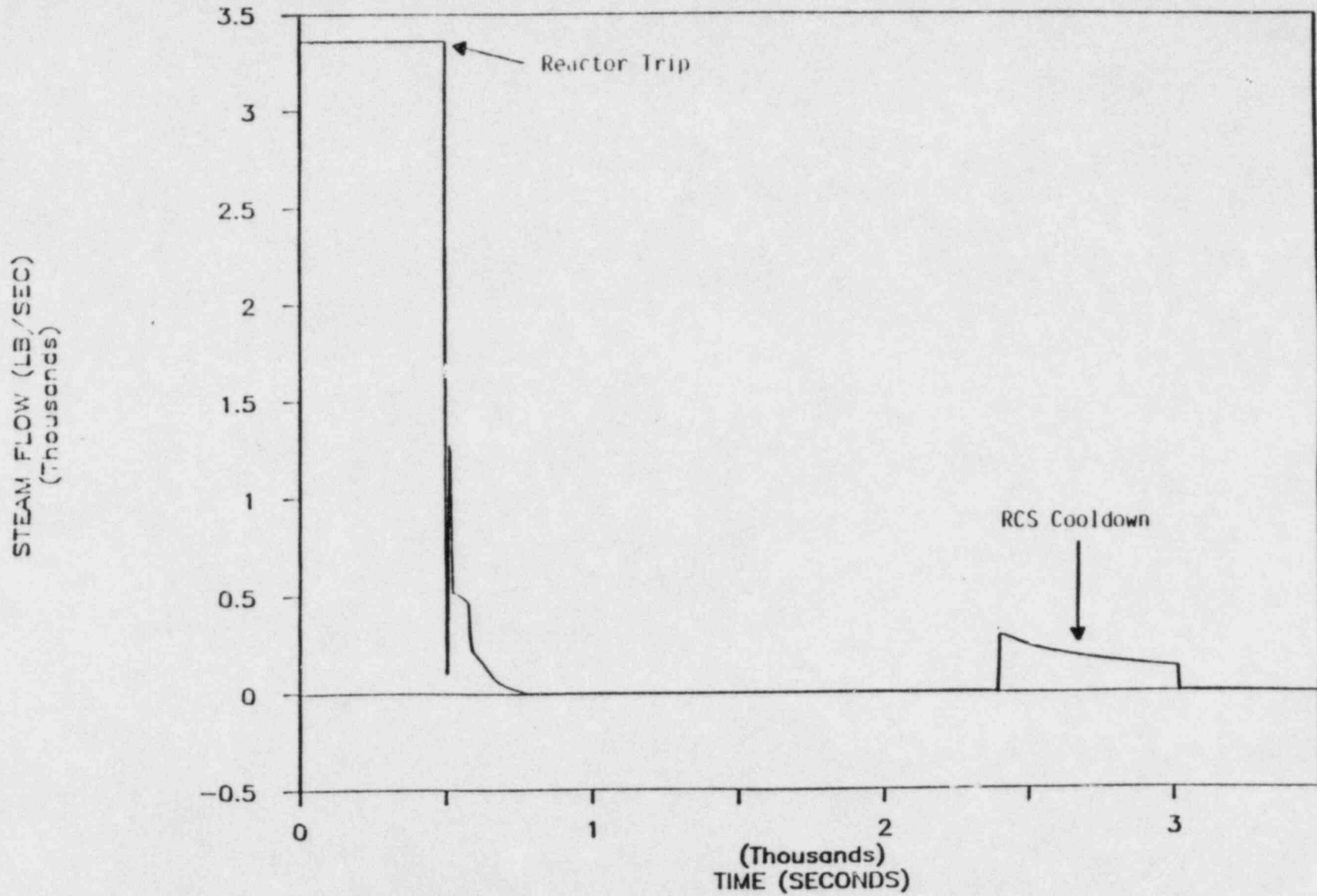


FIGURE 4-29 AFW AS A FUNCTION OF NR IN FAULTED STEAM GENERATOR
(WORST CASE DOSE)

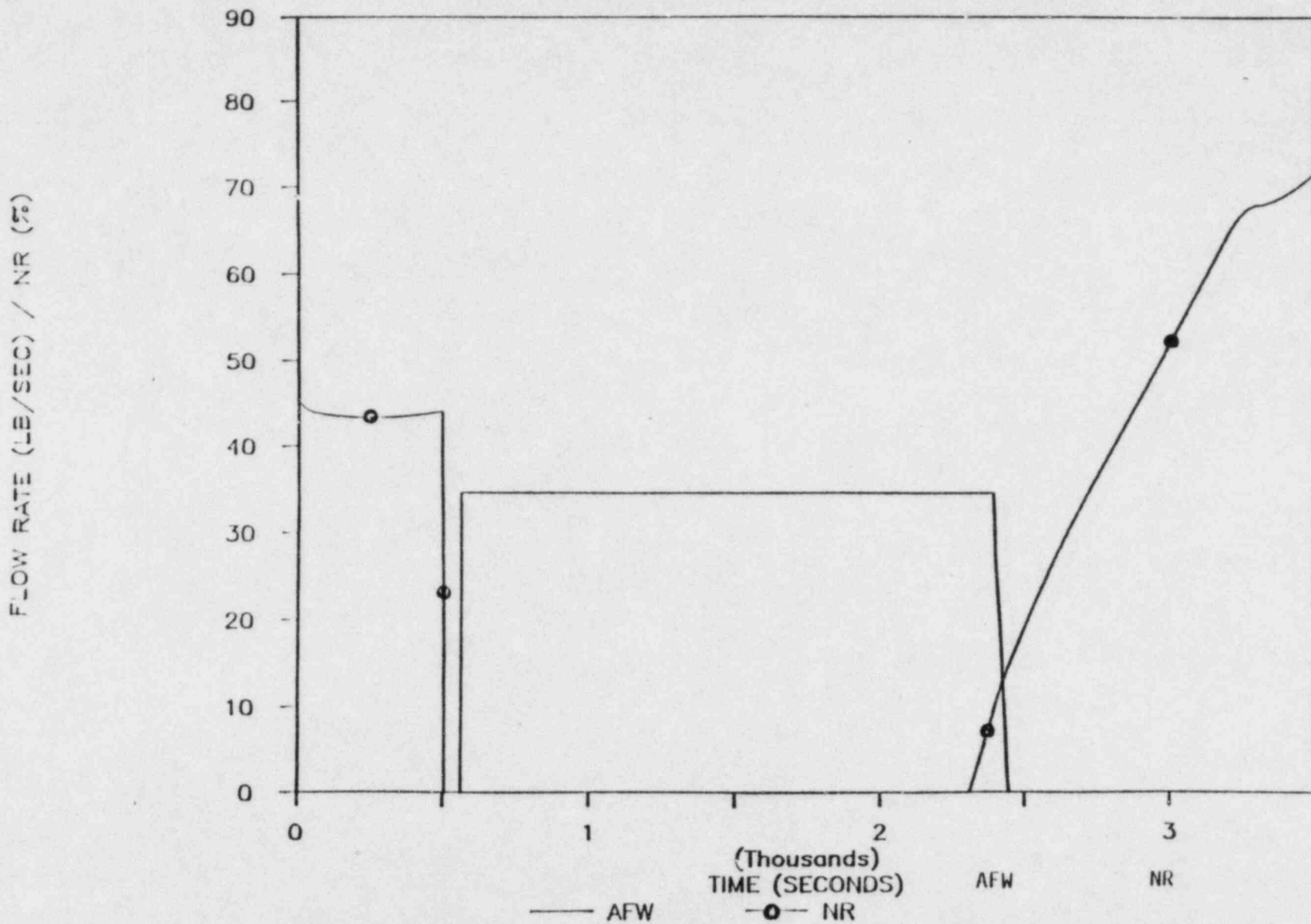
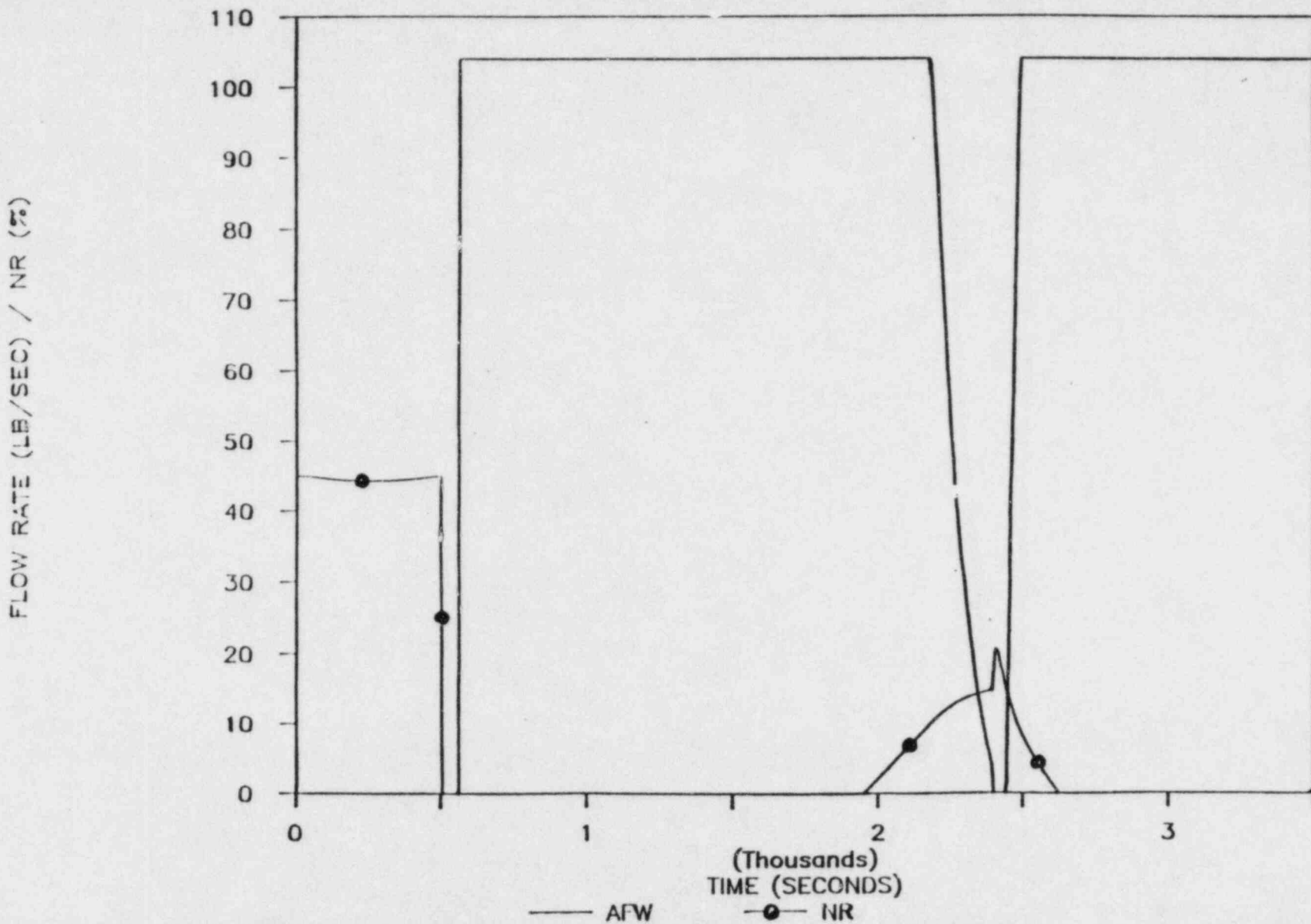


FIGURE 4-30 AFW AS A FUNCTION OF NR IN INTACT STEAM GENERATORS
(WORST CASE DOSE)



5.0 OTHER CONSIDERATIONS

5.1 Water Filled Steam Line

If we assume that the operators do not take timely actions and the faulted steam generator is allowed to overfill, then static loading and water hammer in the steam line must be addressed.

5.1.1 Static Analysis

Weight and thermal stress analyses have been performed for the SNUPPS main steam lines for hot flooded conditions postulated to occur following a SGTR. The result of the analysis showed that the piping stresses caused by flooding the steam line were within allowable code values.

5.1.2 Dynamic Analysis--Water Hammer

At the time overfill is calculated to occur, sufficient time will have elapsed for the operators to terminate auxiliary feed-water flow to the faulted SG and the addition of water to the SG will be solely from the break flow. The break flow for a double-ended tube rupture is approximately 50 lb/sec or about 1 ft³/sec. At this filling rate, the dynamic forces on the steam piping are not likely to be severe.

In order for water hammer to occur, one of the following situations must exist:

- o Rapid condensation between water and steam;
- o Sudden interruption of high velocity liquid flow (valve closure);
or
- o Entrainment of water in a steam-filled line (slugging).

In the first case, when subcooled liquid comes in contact with steam and a large temperature differential exists, rapid condensation will occur. This rapid condensation creates a low pressure region resulting in accelerated flow toward the condensation site. The water hammer occurs as the steam volume collapses. In the SGTR overfill, however, the large temperature differential does not exist.

The water flowing into the steam line would be relatively hot since it will be a mixture of the hot reactor coolant and existing SG water volume. In addition, the piping and other metallic components in contact with the steam will be hot, by virtue of having been in contact with flowing steam prior to reactor trip, being insulated, and being in contact with steam after the SGTR event. Density gradients within the SG will tend to keep the hottest water at the top of the SG, where the nozzle to the steam line is located. Thus, there will be no significant temperature differential between the steam and water, and no possibility of rapid condensation.

In the second water hammer situation noted above, high velocity fluid is interrupted causing the propagation of potentially destructive pressure waves (water hammer). As the minimum area in the steam line is 1.4 ft², the velocity at which the water will enter the steam line will be at most 0.7 ft/sec. This is well below the flow velocities at which high pressure waves would result from sudden flow interruptions.

In order for slugging to occur, a volume of liquid must exist with a low pressure steam volume on one side and a high pressure "plenum region" on the other. The plenum region must be able to maintain a pressure level higher than the condensing steam volume so that a pressure differential can accelerate the "slug" into the condensing steam volume. At the time that overflow is calculated to occur, primary and secondary side pressures and temperatures in the faulted loop are nearly equal. The SG, therefore, does not have the pressure necessary to propel the slug. Thus, there can be no slug motion toward the isolation valve.

As there are no circumstances that could lead to water hammer in the steam lines, numerical analyses are considered unnecessary.

5.2 Auxiliary Feedwater Line Water Hammer

Given the addition of cold AFW into the feedline, water hammer may result in one of two ways:

- o Rapid condensation of steam void, or
- o Fluid impingement at AFW initiation.

Condensation water hammer can take place if voiding occurs in the main and/or auxiliary feedlines. The probability of feedline voiding has been all but eliminated at the SNUPPS units through use of J-tube feedrings and redundant (three) check valves in the main feed-auxiliary feed lines.

Water hammer from normal injection of AFW into the AFW lines should not be realized given the relatively small flow rates. This conclusion is supported by the successful completion of Preoperational Test CS-03AL04 at Callaway (Reference 6).

Given the test results and unlikelihood of feedline voiding, further analysis is considered unnecessary.

5.3 ARV Technical Specification

As outlined in the steam generator tube rupture analysis, the steam generator atmospheric relief valves are used for SGTR mitigation. Although these valves are properly qualified, they are not presently addressed in either SNUPPS Technical Specifications.

Relative to this issue, each utility will submit its own Technical Specifications Amendment Request concerning the operability of the ARVs in an SGTR event. These amendments will ensure operability

of the valves consistent with the SGTR analysis. The basis for a utility specific Technical Specification for the main steam line ARVs is presented in Appendix E.

REFERENCES

1. SLNRC-84-0044, Steam Generator Tube Rupture Event, 3/16/84.
2. Letter from NRC (B. Youngblood) to Union Electric Company and Kansas Gas and Electric Company, Request for Additional Information--Steam Generator Tube Rupture Event, 6/12/84.
3. SLNRC-84-0129, Steam Generator Tube Rupture Event, 12/3/84.
4. McFadden, J. H., et al, RETRAN-02 - A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems, EPRI NP-1850, May, 1981.
5. Letter from C. O. Thomas (NRC) to T. W. Schnatz (Utility Group for Regulatory Applications), Technical Evaluation Report: RETRAN-02/MOD02 dated September 2, 1984.
6. Preoperation Test CS-03ALO4 Revision 0, Auxiliary Feedwater System Water Hammer Test.
7. NRC Generic Letter No. 85-19, Reporting Requirements on Primary Coolant Iodine Spikes, 9/27/85.

Appendix A - Description of Scoping Code

I. General

The scoping code for steam generator tube rupture (SGTR) events was developed to evaluate manner the effects of operator response times and various assumed single failures. These analyses focus on the secondary side behavior of the SGs and are normalized to RETRAN results..

The methodology of the scoping analyses may be summarized as follows. The 0-2 hour time period following occurrence of a postulated SGTR is divided into six time intervals, corresponding to specific phases of the SGTR event and recovery actions. The durations of the time intervals are established by inputting the time of reactor trip (as calculated by RETRAN) and assumed operator response times for key actions: isolation of auxiliary feedwater (AFW) flow to the faulted SG, initiation of cooldown of the reactor coolant system (RCS), depressurization of the RCS, and termination of safety injection (SI) flow. State points (system pressures, temperatures, etc.) are established for each time interval. These state points are based on RETRAN analyses and the emergency operating procedures for recovery from a SGTR event. For each time interval, heat and mass transfers are integrated and the inventories of water and steam in each SG at the end of the time interval are determined. Water levels in the intact and faulted SGs, possible overflow of the faulted SG, releases of steam or steam/water, releases of radioactive iodine, and 0-2 hour offsite doses are then calculated.

Consistent with the FSAR analysis, loss of offsite power is assumed to occur at the time of reactor trip. This is also the worst case with respect to offsite doses because steam dump and the condenser are unavailable for retention of some of the leaked radioactivity. Various assumed equipment failures can be evaluated. In addition, the tube break may be in the hot or cold leg of the SG and iodine spiking may be in accordance with Case 1 or Case 2, as defined by NRC Standard Review Plan 15.6.3.

The analysis procedure is altered slightly to consider the postulated failure of a stuck-open atmospheric relief valve (ARV). During the depressurization of the failed SG, three additional intervals are utilized, SG pressure and consistent RCS conditions are specified for each time interval, and the time to reach the pressure at the end of each interval is calculated in an iterative manner, using the ARV flow characteristics. These analysis procedures are programmed in Microsoft BASIC for a personal computer.

II. Outline of Calculation Procedure - All Cases Except Stuck Open ARV

A flow diagram of the calculation procedure is given in Figure A-1. As indicated, the following calculations are performed in sequence for each time interval, except as noted.

1. Primary side heat balance to determine the total heat transferred from the RCS to the secondary sides of the SGs.
2. Secondary side conditions, faulted SG.



4.i(a,b,c)

3. Secondary side conditions, intact SGs.



4.i(a,b,c)

4. Iodine behavior.



4.i(a,b,c)

The calculations described in "1", "2", and "3" are bypassed for time interval "1". This is done because the secondary side pressures, temperatures and water and steam inventories remain essentially constant until the reactor trips. The feedwater flow controller compensates for the break flow by throttling feedwater and maintaining constant level in the faulted SG. The calculations described in "4" are performed

for each time interval, except that, for time interval "1", the calculation is modified to account for the fact that most of the steam-borne iodine is carried to the condenser hotwell, where [] remains in the water.

4.i(a,b,c)

III. Outline of Calculation Procedure.- Failed open Atmospheric Relief Valve

Time Intervals

1. Prior to failed-open ARV

The first three time intervals in the calculation that cover the period from occurrence of the SGTR to initiation of RCS cooldown are calculated in the same manner as in the basic calculation (Section II.).

2. After failed-open ARV

Following time interval "3", six additional time intervals are utilized to calculate the depressurization of the faulted SG. The thermodynamic end states of these six intervals are specified to conform to the results of a RETRAN analysis, in which the ARV fails open upon the initial demand following reactor trip. The length of each interval is then calculated iteratively, using the rated steam release characteristic of the ARV.

FIGURE A-1

Outline of Calculation - Scoping Code

INPUT

Conditions representing plant state (single failure, etc.).
Operator action times.
Initialize to steady state operation prior to SGTR.

TIME INTERVAL

Advance time interval counter ($N = N+1$).

PRIMARY SIDE CALCULATIONS

Decay heat (per ANS).
 T_C based on secondary pressure.
 T_H based on decay heat and natural circulation flow correlation.
Change of latent heat of reactor coolant.
Latent heat of SI.

BREAK FLOW AND FLASHED FRACTION

Break flow based on consideration of pressure drop from SG plena to break location.
Hot and cold leg contributions to break flow.
Fraction of break flow that flashes.

FIGURE A-1 (Continued)

MASS AND ENERGY BALANCE IN FAULTED AND INTACT SGs

Mass addition from break.
Mass addition from AFW (initially assume no throttling of AFW by operators).
Apportion total energy transferred from primary among SGs.
Latent heat of AFW.
Change of latent heat of steam and water in SG.

STEAM PRODUCED

If net energy addition is positive.
Can have subcooled water and non-thermal-equilibrium between steam and water if net energy addition is negative.
In this case steam produced is zero.

WATER INVENTORY IN SG

Water present at start of time interval.
Water added by break flow and AFW.
Water lost by steam produced.
Water present at end of interval.

WATER LEVEL

Compute void fraction
Correct water volume for voids.
Check water level vs. maximum level to be controlled by operators. If too high, iterate on AFW addition.
Compare water volume vs. volume available (SG plus steam line). If water volume exceeds available volume, excess water is released to atmosphere.

FIGURE A-1 (Continued)

STEAM INVENTORY IN SG

Available volume is SG plus steam line volume minus water volume.
Compare with steam inventory at start of interval plus net steam produced.
Excess steam is released to atmosphere.

IODINE CONCENTRATIONS IN RCS AND SG WATER

Case 1 or Case 2 iodine spiking model.
Concentration in RCS based on release from fuel, loss through break, and dilution by SI.
Concentration in SG based on addition from break and leakage, loss to atmosphere, and dilution by AFW.

IODINE RELEASED

Via steam and water released. Partitioning factor (PF) is 1 for flashed fraction of break flow and water released. PF is 100 for steam released.

PRINT INTERMEDIATE DATA

Optional printout at end of each time interval.

PRINT SUMMARY DATA

Summations for 0-2 hours.

APPENDIX B Description of RETRAN Model

I. INTRODUCTION

The RETRAN version used was RETRAN-02 MOD 003 (Reference B-1). The NRC-issued Safety Evaluation Report on RETRAN-01 MOD 003 and RETRAN-02 MOD 002 states, concerning the identified coding errors, "The staff requires that these errors be corrected in the approved application of these codes (Reference B-2). RETRAN-02 MOD 003 is the corrected version of RETRAN-02 MOD 002 and is therefore deemed appropriate for use in safety-related applications such as the SGTR accident.

II. GENERAL DESCRIPTION

The SNUPPS SGTR nodding diagram employed in the RETRAN analysis is shown schematically in Figure B-1. The RETRAN model utilizes two loops; one represents a single loop of the plant while the second loop combines the remaining three plant loops into one. Noding of this manner allows analysis of asymmetric transients such as an SGTR.

The pressurizer is positioned on the lumped loop. This placement is typical of that for other RETRAN models for similar plants.

The reactor vessel is modeled with eight control volumes as shown in Figure B-1; one volume for the downcomer region, one volume for the core bypass region, three volumes for the active core region, one volume each for the upper plenum and the lower plenum and the upper head.

The primary coolant piping and steam generators are modeled in some detail so that area changes and elevation differences would be included in the model. The hot leg, pump suction leg, pump, and cold leg were represented by one volume each. Six volumes are used to model each steam generator; one each for the inlet and outlet plenums and four in the U-tube region. The pressurizer, pressurizer surge line, and pressurizer spray line are each represented by a single volume.

Heat conductors are modeled only for the steam generator tubes and the active length of the reactor core. The active length of steam generator tubes has four heat conductors (one for each fluid volume) and the reactor core has three axial core conductors (one for each fluid volume) to describe the active core.

The SGTR model consists of 37 fluid volumes, 64 junctions and 11 heat conductors. The nodalization was selected so as to identify important hydraulic features of the system and provide sufficient detail to attain accuracy in solution. A summary of the volume description is given in Table B-1. Table B-2 gives a summary of the flow junctions connecting the fluid volumes.

III. COMPONENT DESCRIPTIONS

Steam Generators

Nodalization

The primary portion of the steam generator is divided into four nodes. These four nodes represent the 5626 U-tubes associated with the Model F. According to Figure B-1, the single loop nodes are identified by Volumes 13 through 16 and the lumped loop nodes are identified by Volumes 3 through 6.

The secondary side of the steam generators is represented as a single saturated volume. This noding is a significant simplification for the actual plant geometry but is consistent with the modeling technique employed for most non-LOCA transients in the FSAR.

Initialization

Since the secondary side is modeled by a single volume and [4.i(a,b,c)
]

In addition to initializing with the proper heat transfer characteristics, steam and liquid mass inventories must be initially correct. The initial steam generator liquid mass depends on the input initial conditions and [4.i(a,b,c)
]

Heat Conductors

The steam generator tubes are divided into four equal conductors, one conductor for each SG tube volume, in order to provide one to one correspondence for heat transfer. Thus, the inside and outside surface areas and volume of metal for each conductor are one-fourth of the value of these parameters calculated for all the SG tubes. The eight heat conductors for the two steam generators are shown in Figure B-1.

Feedwater

Main Feedwater

The main feedwater is represented as a fill junction and is identified as junction 35 for the lumped loop and Junction 37 for the single loop.

Auxiliary Feedwater

The auxiliary feedwater is also represented as a fill junction and is identified as Junction 65 for the lumped loop and Junction 64 for the single loop. Although Figure B-1 shows the auxiliary feedwater junction elevation below that of the main feedwater junction, the model input has the auxiliary feedwater junction correctly positioned as in the plant.

Main Steam Line

The main steam line from the steam generator outlet nozzle inclusive to the main steam isolation valve is modeled as a single volume. According to Figure B-1, the single loop steam line is identified as Volume 61 whereas the lumped loop is identified as Volume 60.

Safety and Relief Valves

In the event of steam generator secondary over-pressurization, five safety valves and one atmospheric relief valve can open to relieve pressure. The actuation of the valves is controlled by trip functions that monitor pressure of the secondary side.

Pressurizer

The pressurizer, Volume 21 on Figure B-1, is modeled as a single non-equilibrium fluid volume with phase separation. This option uses the equations for mass and energy balances in RETRAN to permit the pressurizer volume to have different temperatures in the liquid and vapor regions of the pressurizer during a transient.

Safety, Relief and Spray Valves

The model includes the pressurizer relief and safety valves, pressurizer spray, but does not include pressurizer heaters. The pressurizer relief and safety valves are activated by trip functions which are set to open and reset on pressurizer pressure. The pressurizer spray is controlled by a control system acting upon a pressurizer pressure error signal. The relief and safety valves discharge to the pressurizer relief tank, Volume 43.

Reactor Vessel

Lower Plenum

The lower plenum, Volume 25, includes the lower head and the volume inside the lower internals assembly below the core.

Upper Plenum

The region above the core consists of an upper plenum and upper head volumes as illustrated in Figure B-1. The flow paths in this region represent both the main flow path from the core to the hot leg piping and the downcomer to upper head leakage of approximately 1.5% of total flow.

Downcomer

The downcomer, Volume 24, is the annular volume between the reactor vessel and the outer surface of the lower barrel assembly. The volume extends from the upper flange of the lower barrel assembly to the bottom of the lower barrel assembly.

Core

The core is divided into three axial nodes. The length of each of these fluid volumes is one-third the average active length of a fuel assembly. The total flow area in the core is composed of the difference between the area within the core baffle and the total cross section area of the fuel rods, instrumentation tubes and RCCA thimbles.

RETRAN determines the core power generation by employing the kinetics model [

4.i(a,b,c

]

Core Heat Conductors

There are three core heat conductors numbered 1 through 3. These provide a one for one correspondence with each core fluid volume numbered 26 through 28. All volume heat conductors have a length equal to their corresponding fluid volumes. The conductivity of the gas in the gap between the fuel and the clad gives an average fuel temperature corresponding to full power.

Core Bypass

The core bypass, Volume 31, consists of the space between the core barrel and the core baffle, the incore instrument tube assembly, and the RCCA thimbles.

Reactor Coolant Pumps

The reactor coolant pumps are represented by the design Westinghouse Model 93A pump homologous performance characteristic curves. For the model, the thermal energy generated by the pumps is added to the reactor coolant system in the pump control volumes, Volumes 9 and 19 as shown in Figure B-1.

Reactor Coolant Piping

The remaining volumes represent the reactor coolant piping. These nodes are identified as Volumes 1-8, 10-18, 20, 22 and 23 on Figure B-1.

Safety Injection

Safety injection to the cold legs of the reactor coolant piping is modeled as fill junctions. Upon reaching the low pressurizer pressure setpoint, the fill junction trips on and emergency core cooling is provided.

Charging and Letdown

The Chemical and Volume Control System functions of normal charging and letdown are not included in this model.

IV. MODELING TECHNIQUES

Reactor Trips

Overtemperature and Overpower ΔT

Both the $OT_{\Delta T}$ and $OP_{\Delta T}$ equations are programmed into RETRAN via linear control systems which trip the reactor if either setpoint is reached.

Pressurizer Pressure

Both extremes of pressurizer pressure are monitored for reactor trip purposes. In addition to reactor trip, safety injection occurs when the low pressurizer pressure setpoint is reached.

SGTR Break Flow

SGTR break flow is modeled with the use of fill junctions and linear control systems. For example, the hot leg side break has a negative fill junction, #71, depleting the primary at a rate identical to what the positive fill junction #69, adds to the secondary. Modeling break flow in this manner facilitates programming into RETRAN any break flow correlation desired (See Appendix D).

Operator Actions

Operator actions are modeled using trip functions in combination with linear control systems which monitor elapsed time and other parameters. For example, if an assumption is made that the operator takes action to isolate the affected steam generator at 16 minutes, then a trip is identified to initiate the necessary responses.

MODELING OPTIONSEnthalpy Transport

The standard enthalpy transport option is used on all the heated or heat exchanging conductors. This involves the three core conductors and the four steam generator conductors in each loop. This option provides a value for junction enthalpy based on known enthalpy at the center of the associated volume.

Pressurizer Model

The non-equilibrium model is used to determine the pressurizer response. This model is a necessity for operational transients because the surge into the pressurizer causes a significant non-equilibrium effect which is not accounted for by the standard equilibrium state solution. This model keeps track of the mass and energy in both liquid and vapor regions allowing different thermodynamic states in each region. The model includes a "flashing" model for movement of vapor from the liquid region to the vapor region and a rainout model for movement of liquid from the vapor region to the liquid region.

The limitations of the non-equilibrium pressurizer model as identified in the SER are recognized and it is noted that at no point in the SGTR transient analyses does the pressurizer completely empty or become water solid.

Temperature Transport Delay

The temperature transport delay model which is employed to model the movement of temperature fronts through the piping volumes is used in Volume []. As identified in the SER, the transport delay option is only used in piping exhibiting a dominant flow direction. 4,i(a,b,c)

Momentum Equation

Of the options available to calculate momentum effects, the complete compressible momentum equation is employed for all junctions in the model. At junctions like the surge line entrance from the hot leg piping it is [4,i(a,b,c)

]

Homogeneous Equilibrium Model

All volumes employed in the model with the exception of the pressurizer and the steam generator secondary are homogeneous equilibrium model volumes. Further, in keeping with the SER limitations, it is noted that for the SGTR transient analyses, no significant voiding occurs on the primary side. The Technical

Evaluation Report portion of the SER warned that the SGTR transient "should not be analyzed for two phase conditions beyond the point where significant voiding occurs on the primary side."

Bubble Rise Model

The steam generator secondary side employs the []

4.i(a,b,c)

References

- B-1 McFadden, J.H., et al, RETRAN-02 - A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems, EPRI NP-1850, May, 1981.
- B-2 Safety Evaluation Report on RETRAN-01 MOD 003 and RETRAN-02 MOD 002, September 4, 1984, Page 3.

TABLE B-1. CONTROL VOLUME DESCRIPTIONS

<u>Control Volume No.</u>	<u>Description</u>
1 (11)*	Hot leg pipe - includes RV outlet nozzle and steam generator inlet nozzle
2 (12)	Steam generator primary inlet volume and tubesheet volume
3 (13)	Steam generator tubes vertical upflow section
4 (14)	Steam generator tubes upflow includes half of U bend
5 (15)	Steam generator tubes downflow includes half of U bend
6 (16)	Steam generator tubes vertical downflow section
7 (17)	Steam generator primary outlet tubesheet and outlet plenum
8 (18)	Crossover pipe - steam generator outlet nozzle to RC pump
9 (19)	RC pump
10 (20)	Cold leg pipe - RC pump to RV inlet nozzle
21	Pressurizer
22	Pressurizer surge line
23	Pressurizer spray line
24	Reactor vessel downcomer annulus
25	Reactor vessel lower plenum
26	Lower third of core active length
27	Middle third of core active length
28	Upper third of core active length
29	Core outlet plenum
30	Reactor vessel upper head

TABLE B-1. CONTROL VOLUME DESCRIPTIONS (Cont'd)

<u>Control Volume No</u>	<u>Description</u>
31	Core bypass
32 (33)	Steam generator secondary
43	Pressurizer Relief Tank (Time Dependent Volume)
57	Atmosphere (Infinitely Large Volume)
60 (61)	Main steam line inclusive to the MSIVs

*Control volume numbers in parenthesis are associated with loop representing the single steam generator and the other control volume numbers are for the lumped loop.

TABLE B-2. FLOW JUNCTION DESCRIPTIONS

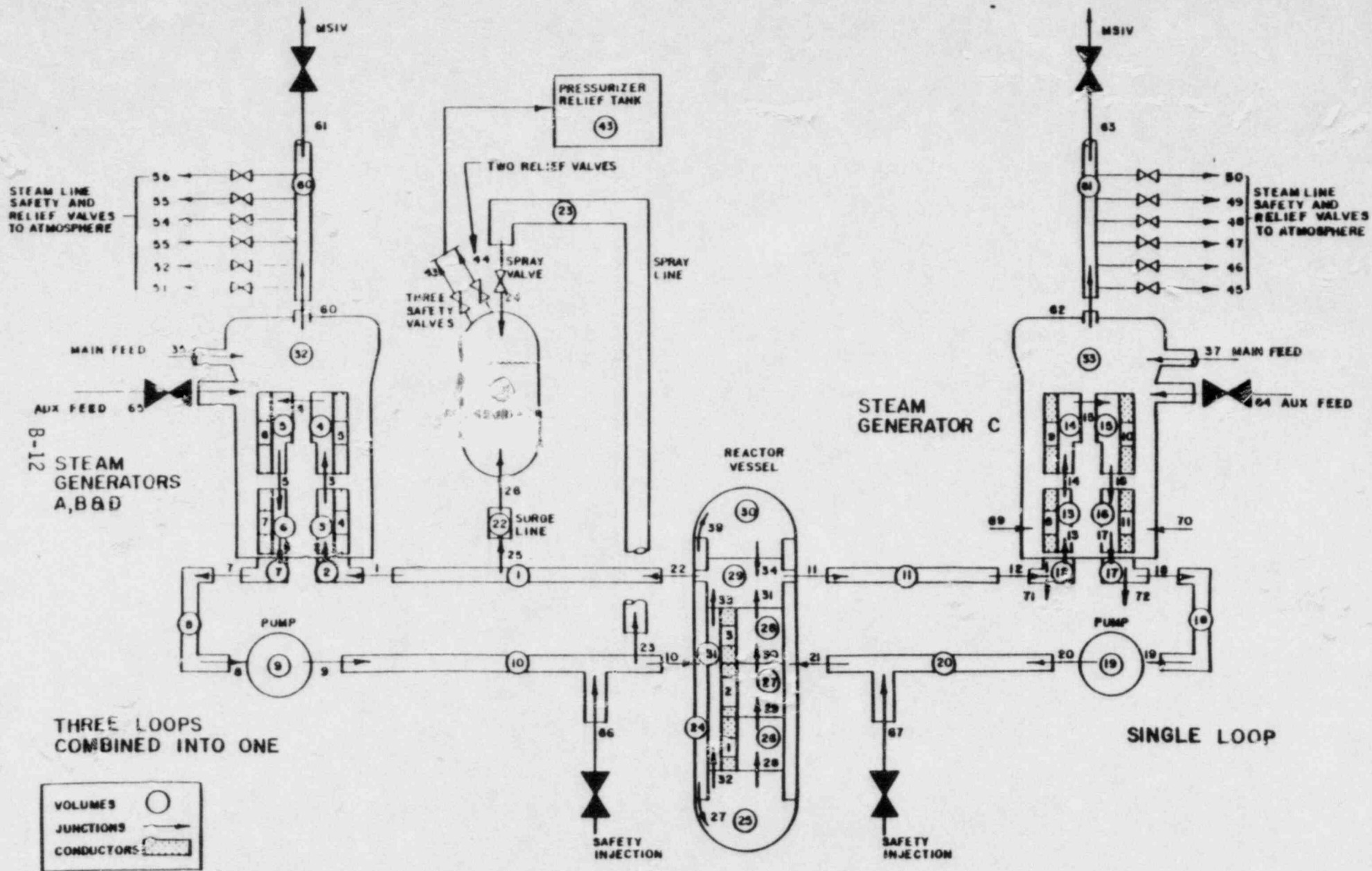
<u>No.</u>	<u>Description</u>
1 (12)*	Hot leg piping to steam generator inlet plenum
2 (13)	SG inlet plenum to 1st segment SG tubes
3 (14)	1st segment SG tubes to 2nd segment SG tubes
4 (15)	2nd segment SG tubes to 3rd segment SG tubes
5 (16)	3rd segment SG tubes to 4th segment SG tubes
6 (17)	4th segment SG tubes to SG outlet plenum
7 (18)	SG outlet plenum to crossover piping
8 (19)	Crossover piping to pump
9 (20)	Pump to cold leg piping
10 (21)	Cold leg piping to reactor vessel (RV) downcomer
22 (11)	Upper plenum (core outlet) to hot leg piping
23	Cold leg piping to pressurizer spray line
24	Pressurizer spray line to pressurizer (spray valve)
25	Hot leg piping to surge line
26	Surge line to pressurizer
27	Downcomer to lower plenum
28	Lower plenum to bottom active core control volume
29	Bottom active core volume to middle active core volume
30	Middle active core volume to upper active core volume
31	Upper active core volume to upper plenum
32	Lower plenum to core bypass

TABLE B-2. FLOW JUNCTION DESCRIPTIONS (Cont'd)

<u>No.</u>	<u>Description</u>
33	Core bypass to upper plenum
34	Upper head to upper plenum
35 (37)	Feedwater flow to SG secondary
39	Upper head cold leg leakage
43	Pressurizer safety valve to PRT
44	Pressurizer relief valve to PRT
51 (45)	Main steam line safety valve to atmosphere
53 (47)	Main steam line safety valve to atmosphere
54 (48)	Main steam line safety valve to atmosphere
55 (49)	Main steam line safety valve to atmosphere
56 (50)	Main steam line relief valve to atmosphere
60 (62)	SG secondary to main steam line
61 (63)	Steam line fill junction
65 (64)	Auxiliary feed flow to SG secondary
66 (67)	Safety injection flow to cold leg
69-72	Break flow fill junctions

*Junction numbers in parenthesis represent the junction corresponding to the single steam generator RCS loop.

FIGURE B-1



NODING DIAGRAM USED IN RETRAN ANALYSIS

Appendix C - Verification of RETRAN and Scoping Code

I. Scoping Code

Verification of the scoping code has been accomplished by independent review. The formulation and development of all equations was reviewed for adequate representation of the physical processes and for accuracy. The program listings were checked for accurate representation of the equations developed to represent the physical processes. The Scoping code was reviewed for:

- proper BASIC syntax and statement structure
- proper variable assignments - variables used in calculations had been previously assigned values
- subscripts of subscripted variables were in the range declared in the DIM statements
- possible Illegal Function Calls (square root of a negative number) and possibilities for Division by Zero errors.

The validity of the method of analysis has been demonstrated by comparing calculated results obtained with the scoping code to (1) the FSAR analysis and (2) RETRAN runs. The results of these comparison analyses are described below.

A. FSAR Analysis

In order to compare with the FSAR analyses, the Scoping Code was modified to incorporate FSAR break flows and also the hot and cold leg temperatures given in Figure 15.6-3B of the FSAR instead of temperatures calculated internally by the program.

An AFW flow of 235 gpm to each of two intact SGs has been assumed. A break flow rate of 60 lb/sec has been assumed, consistent with the break flows given in the FSAR. A total leak rate of 1 gpm to the intact SGs has been assumed as in the FSAR and the initial iodine concentration (equivalent I-131) in these SGs has been assumed to be 0.1 μ Ci/g, as in the FSAR. The initial water levels in all SGs have been assumed to be at nominal level less 5% error allowance (45% of narrow range level).

The FSAR analysis has been simulated by running the program with the operator action times as follows:

- | | |
|--|---------|
| - Terminate AFW to faulted SG | 28 min. |
| - Initiate RCS cooldown | 29 min. |
| - Complete RCS depressurization
(terminates break flow) | 30 min. |
| - Terminate SI | 31 min. |

Results of the analysis are as follows:

	<u>Scoping Code</u>	<u>FSAR</u>
Reactor power, Mwt	3636.	3636.
Faulted SG (0-2 hours)		
Initial level, %	45.	*
Final level, %	6.5	*
RC discharged to SG, lbs	108,000.	107,980.
Average flashed RC, %	1.9	17.
Steam release, lbs	66,266	61,860.
Intact SGs (0-2 hours)		
Primary to secondary leakage, lbs	691	250.
Average flashed RC, %	4.2	0
Feedwater flow, lbs	1,321,932	1,350,000.
Steam release, lbs	489,713	451,000.
Iodine Released & Offsite Doses at Exclusion Area Boundary (0-2 hours)		
- Case 1 iodine spiking model:		
Equivalent I-131, Ci	5.4	178.7
Thyroid dose (Callaway), R	0.6	18.
- Case 2 iodine spiking model:		
Equivalent I-131, Ci	44.9	332.5
Thyroid dose (Callaway), R	4.6	43.

Offsite doses are given for Callaway because they are slightly larger than for Wolf Creek.

The difference in releases and doses for the case 2 iodine spiking model are primarily related to the difference in the fraction of the RCS break flow that flashes. The FSAR flashed fraction corresponds to the pre-trip hot leg fluid temperature and does not consider the reduction in hot leg temperature after reactor trip or the fact that a substantial fraction of the

* Not stated in FSAR

break flow is at cold leg temperature. The difference in releases and doses for the case 1 iodine spiking model also reflects a more realistic treatment: Early in the event, when the flashed fraction is high, the iodine concentration in the RCS is low (on the order of $1 \mu\text{Ci/g}$): towards the end of the event, when the iodine concentration in the RCS has increased, the flashed fraction of the break flow is small. The average flashed fraction in the intact steam generators (4.2) is higher than that in the faulted steam generator (1.9) because the code assumes all leakage in the intact steam generators is at the hot leg temperature.

B. RETRAN Analyses

Comparison results are shown in Figures C-1 through C-4. Figures C-1 and C-2 are for the case of a cold leg break and are compared to RETRAN cold leg break results. The results are in reasonably close agreement with RETRAN. Figures C-3 and C-4 are for the case of a stuck open atmospheric relief valve. Again, the results are in reasonably close agreement with RETRAN results for that case.

II. RETRAN

The following discussion presents a comparison of the SNUPPS RETRAN plant model results for a steam generator tube rupture (SGTR) event with the results given in the Final Safety Analysis Report (FSAR). The RETRAN calculated thermal and hydraulic responses are in good agreement with those given in the FSAR.

FSAR Analysis Assumptions

The methods and assumptions for the RETRAN analysis were similar to those of the original FSAR. To perform this comparison, the RETRAN break flow model was modified to use the same as that employed in the FSAR, the modified Zaloudek correlation.

The assumptions and initial conditions used in the RETRAN analysis are generally identical to those used in the FSAR. The single failure assumption was the loss of both the turbine driven AFW pump and the motor driven AFW pump feeding the faulted SG. Additional assumptions utilized in this comparison that are not listed with the FSAR analysis but are consistent with that analysis are as follows:

1. Prior to reactor trip, main feedwater (MFW) flow matches steam flow minus the break flow.
2. MFW isolation valve closes in 20 seconds with a delay of 1.5 seconds.

3. Safety injection (SI) is initiated by low pressurizer pressure at 1755 psia.
4. SI is initiated 25 seconds after reaching the low pressurizer pressure setpoint.
5. SI is delivered at 70°F. The rate of flow is determined by Figure 15.6-3 in the FSAR.
6. Auxiliary feedwater is initiated 60 seconds after reaching the low pressurizer pressure setpoint.
7. AFW at 70°F is delivered to the intact steam generators.
8. Atmospheric relief valve setpoint is 1155 psia.
9. Initial water volume in the pressurizer is 1070 ft³.
10. Water level in the steam generator is at 45% of the narrow range.
11. Chemical and volume control system (CVCS) makeup flow is not credited.
12. The break is located at the cold leg of the steam generator. The enthalpy of the fluid corresponds to that of the inlet plenum.
13. Reactor trip occurs automatically as a result of the overtemperature delta T trip signal.
14. Loss of offsite power occurs at reactor trip.
15. During the initial 30-minute period following the accident, the operator is assumed to throttle the auxiliary feedwater flow to match the steam flow, when possible, in all steam generators.
16. The operator identifies the accident type and terminates break flow to the affected steam generator 30 minutes after accident initiation.

Comparison of RETRAN and FSAR Results

Table C-1 provides a time sequence of events.

Plots of key parameters from both the RETRAN and FSAR analyses for this event are shown in Figures C-5 through C-14. Figure C-5 indicates that the initiation of safety injection flow does not repressurize the primary system in as short a period of time for the RETRAN analysis as it does for the FSAR analysis.

The flow coastdown predicted by RETRAN is faster than the FSAR and this results in a higher average RCS temperature (T_{AVG}) for a short time during the transient (Figure C-6). After SI initiation, the shrinkage of RCS volume (Figure C-7) due to decreasing RCS T_{AVG} and loss of fluid through the break is partially compensated by the SI flow. As shown in Figures C-6 and C-7, the pressure of the primary system starts to turn around as the decrease in RCS average temperature stabilizes at natural circulation conditions.

The initial break flow agrees with that given in the FSAR. The break flow calculated by the modified Zaloudek correlation in RETRAN would be in excellent agreement with that predicted in the FSAR (Figure C-8) if there were no differences in the primary system pressure (Figure C-5). It should be noted that the choked flow correlation, break location and break size are among the assumptions which are not explicitly stated in the FSAR; however, this information was obtained through discussions with Westinghouse.

Pressure and temperature of the faulted SG are plotted as a function of time as shown in Figures C-9 and C-10. The prediction by RETRAN agrees with that given in the FSAR. SG masses as calculated by RETRAN agree with those given in the FSAR (Figures C-11 and C-12). Also, RETRAN predicts a liquid volume in the faulted SG comparable to that given in the FSAR (Figure C-13).

Steam flow via relief/safety valves is shown in Figure C-14 and good agreement is obtained.

TABLE C-1
Time Sequence of Events

Event	Time (Sec)	
	FSAR	RETRAN
Tube Rupture Occurs	0.0	0.0
Reactor Trip Signal	198.9	198.9
Rod Motion	200.9	200.9
Feedwater Terminated	200.9	200.9
SG Relief Valve Open	204.0	204.1
SG 1st Safety Valve Open	*	206.6
SG 2nd Safety Valve Open	*	208.5
SG 2nd Safety Valve Closed	*	219.6
SG 1st Safety Valve Closed	*	238.4
Safety Injection Signal	335.2	408.3
Safety Injection	360.2	433.3
Auxiliary Feedwater Injection	396.0	469.3
Operator Takes Action to Isolate and Cooldown	1800.0	1800.0

*Not given in FSAR

FIGURE C-1 TOTAL BREAK FLOW IN FAULTED STEAM GENERATOR
(Worst Case Potential Overfill)

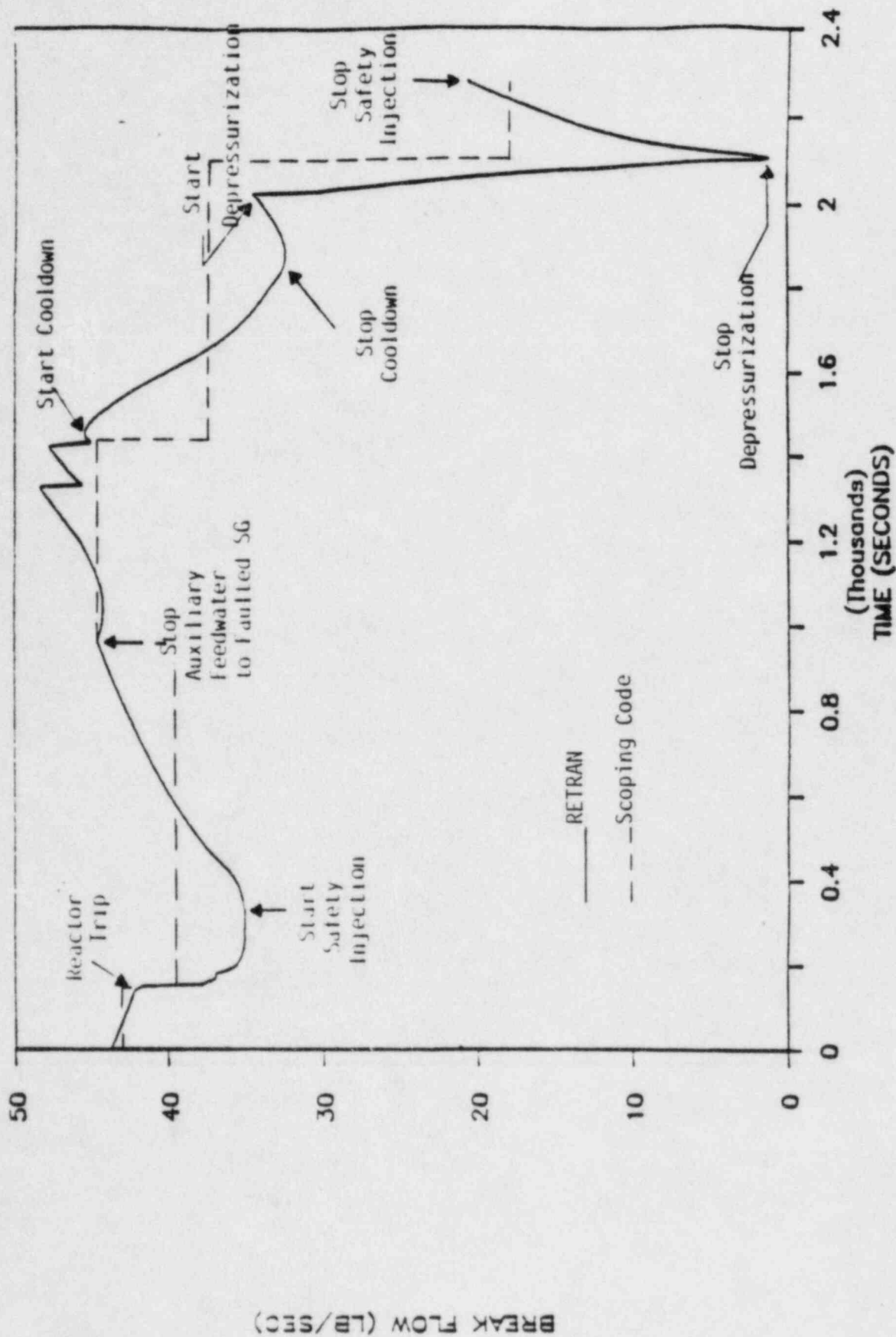


FIGURE C-2 MIXTURE VOLUME IN FAULTED STEAM GENERATOR
(Worst Case Potential Overfill)

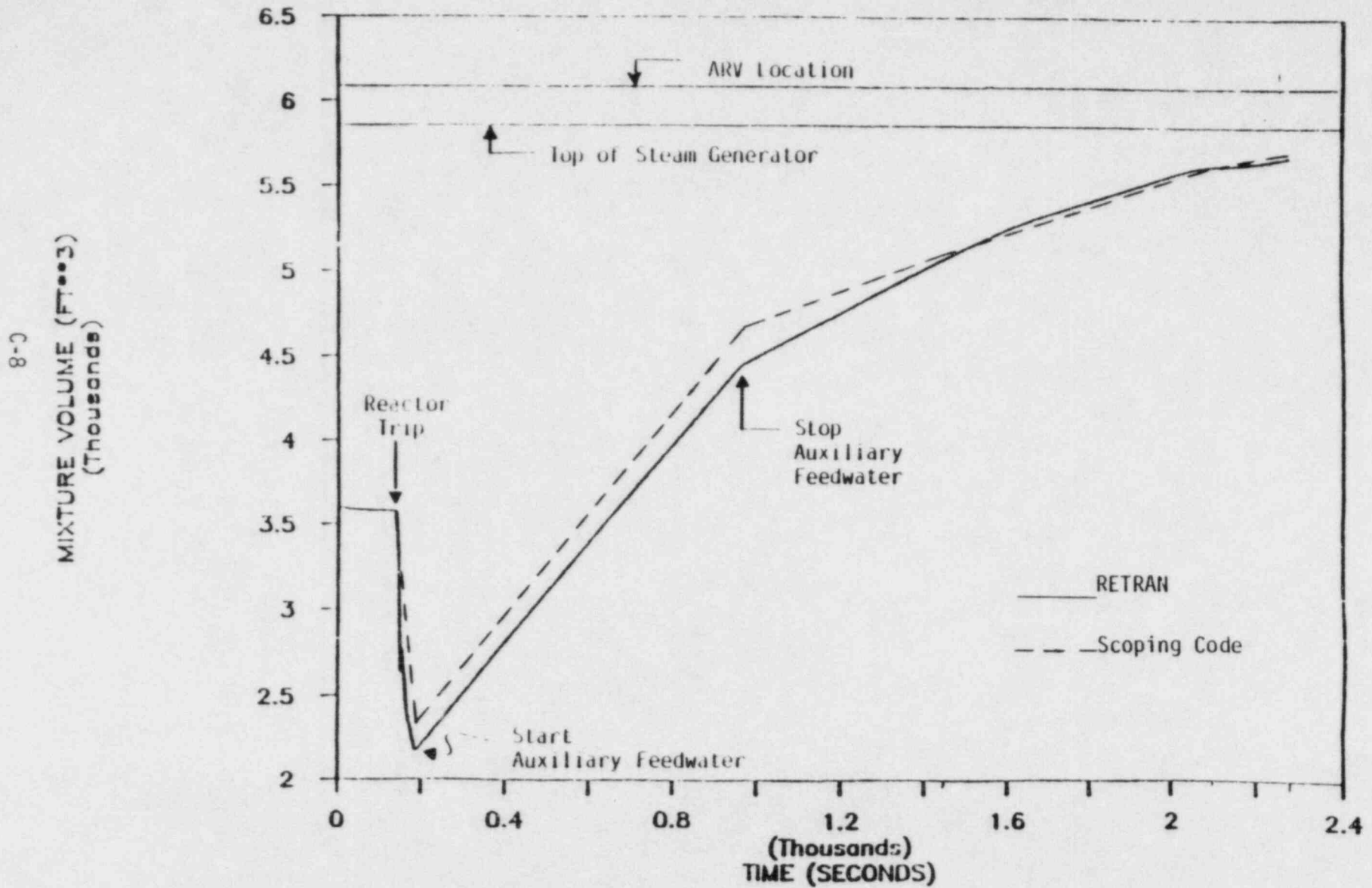


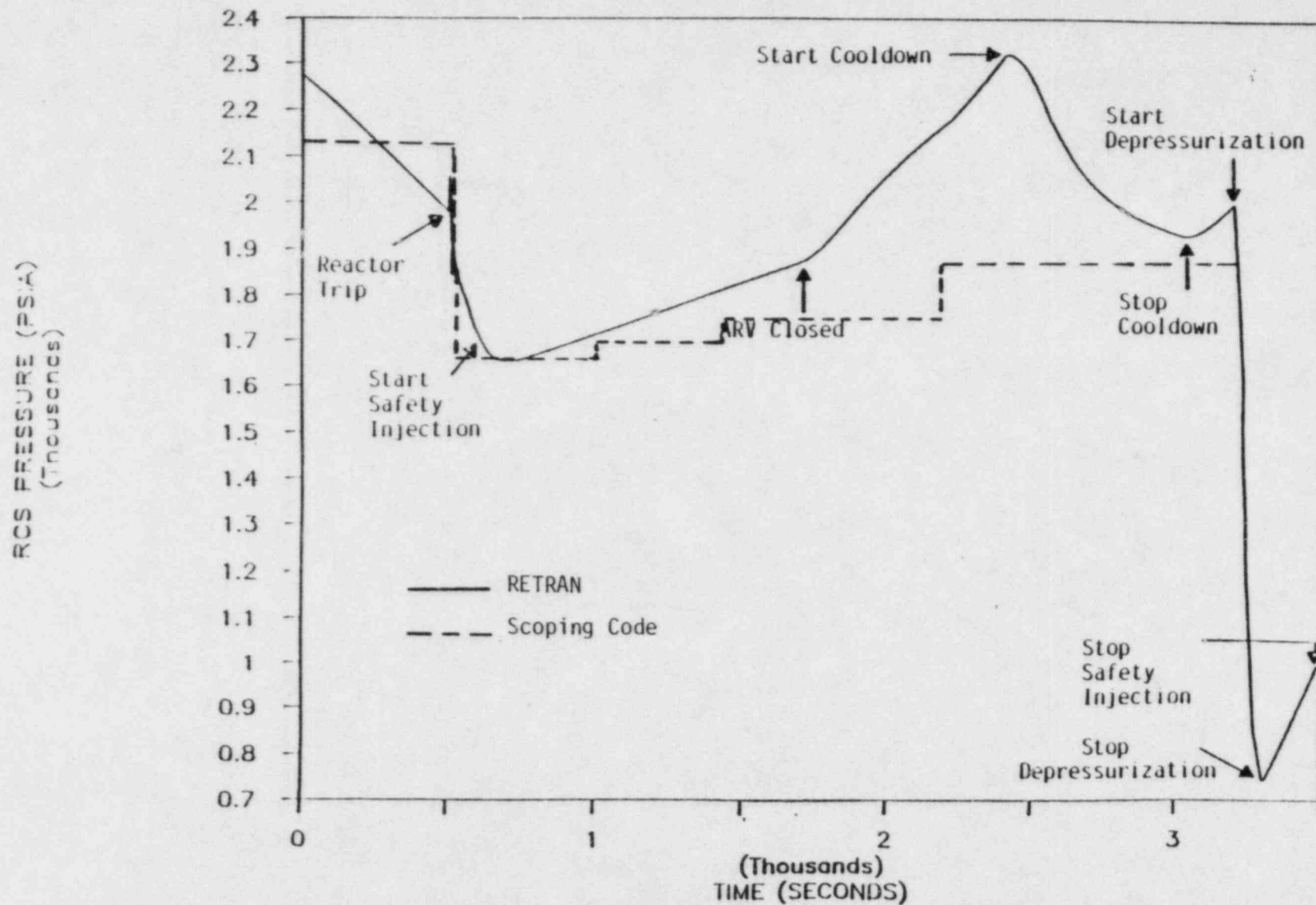
FIGURE C-3 REACTOR COOLANT SYSTEM PRESSURE
(WORST CASE DOSE)

FIGURE C-4 STEAM GENERATOR PRESSURE
(WORST CASE DOSE)

C-10

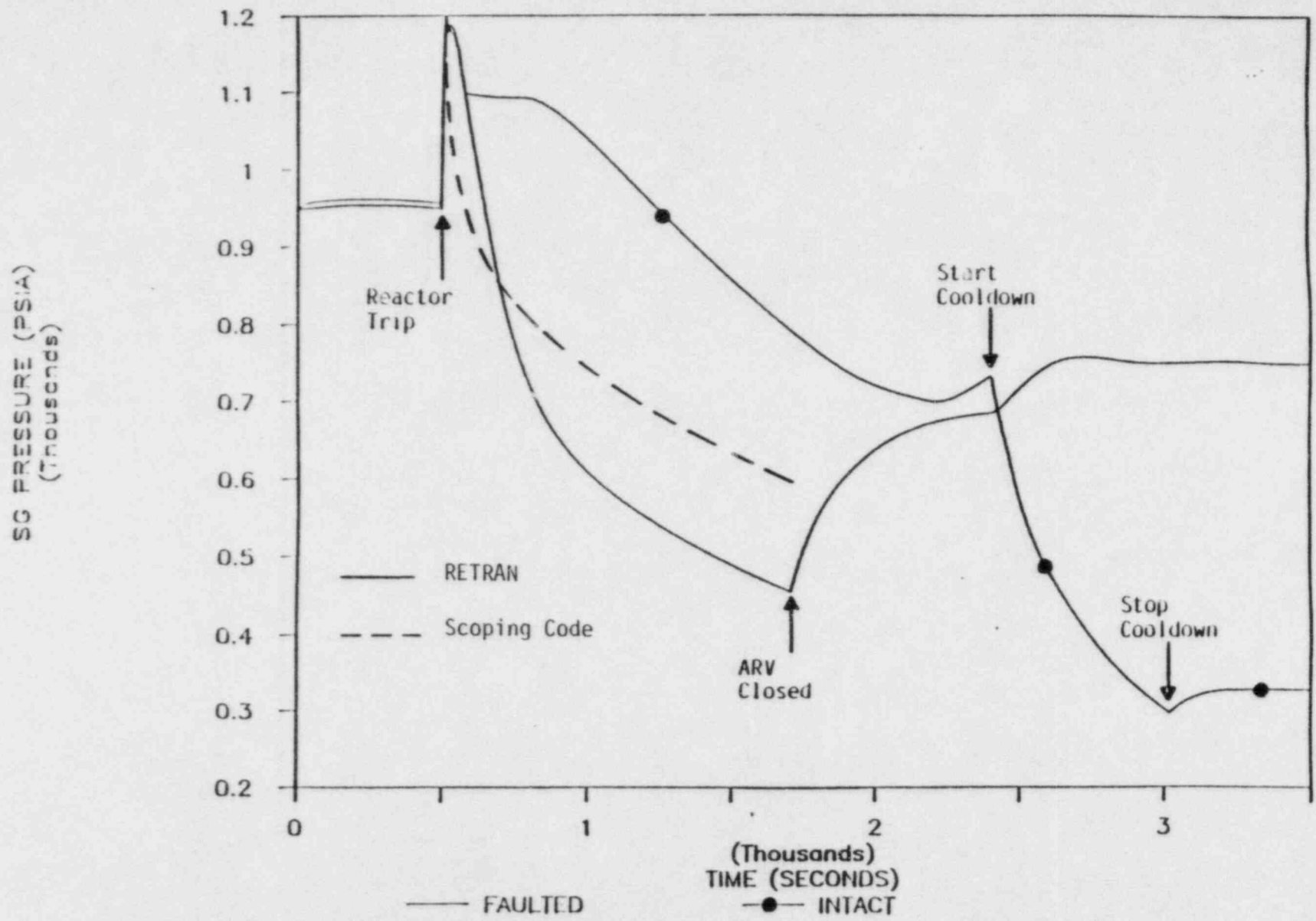


FIGURE C-5

RCS PRESSURE RESPONSE TO SGTR

C-11

CORE PRESSURE (PSIA)
(Thousands)

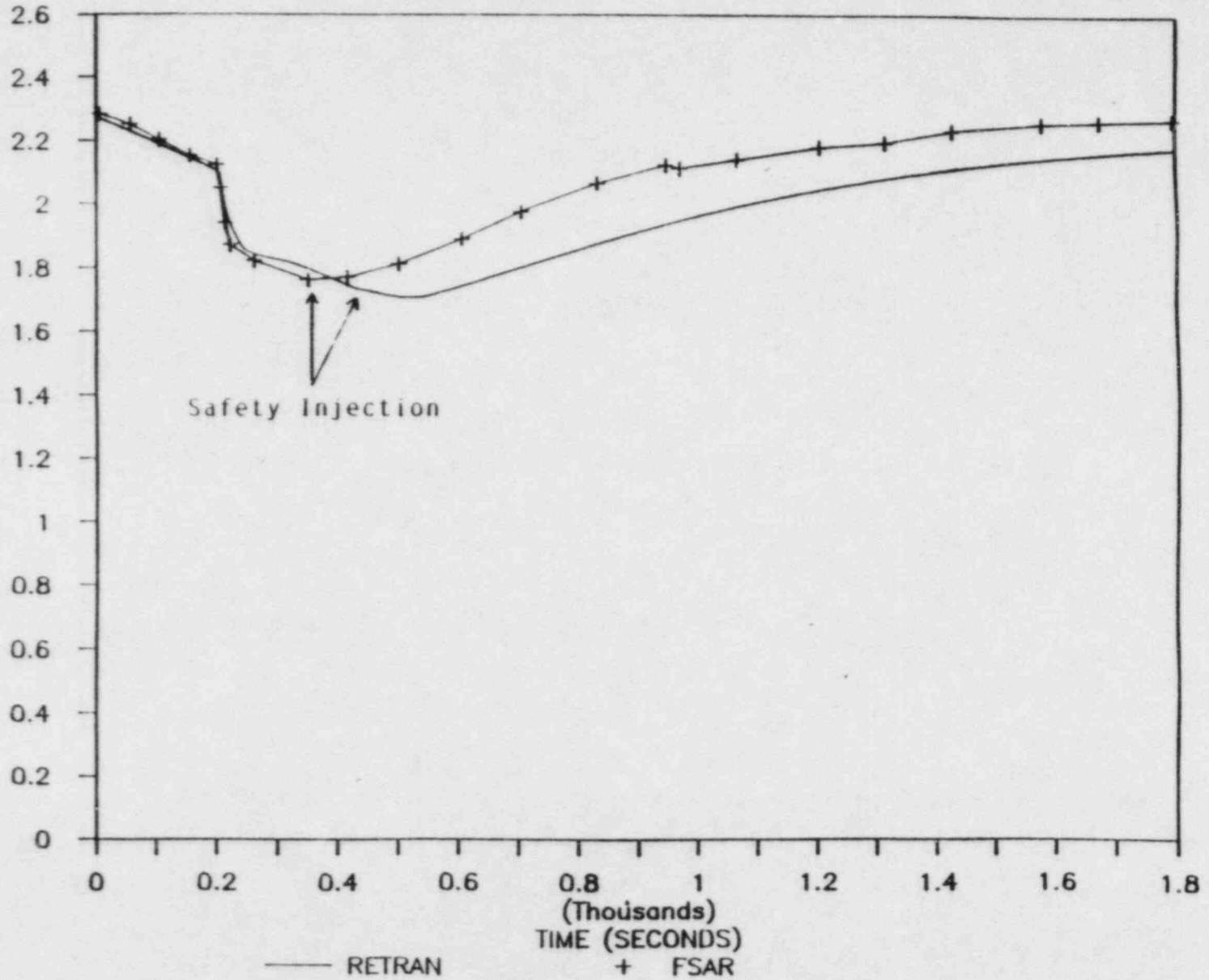


FIGURE C-6

RCS TEMPERATURE RESPONSE TO SGTR

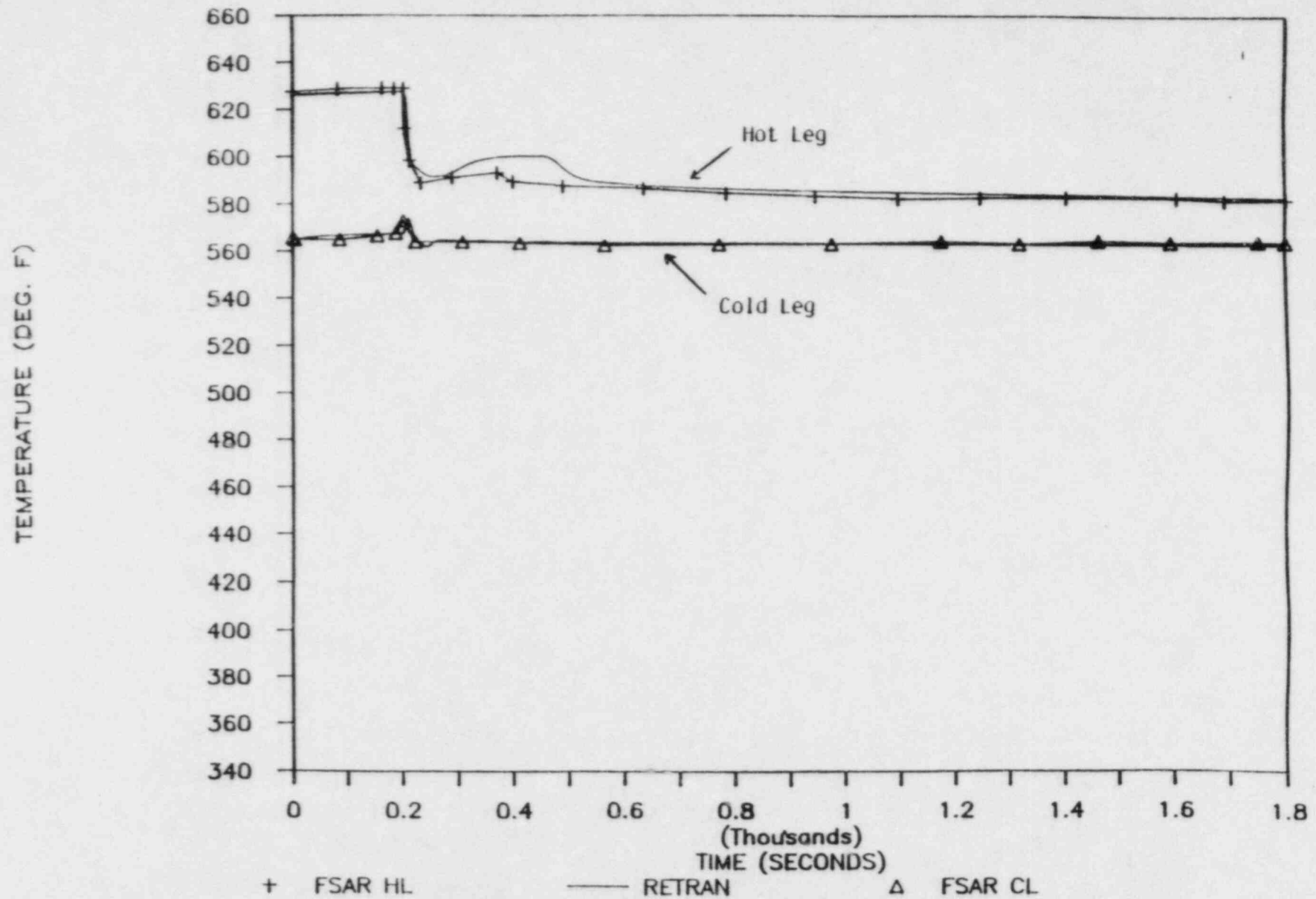
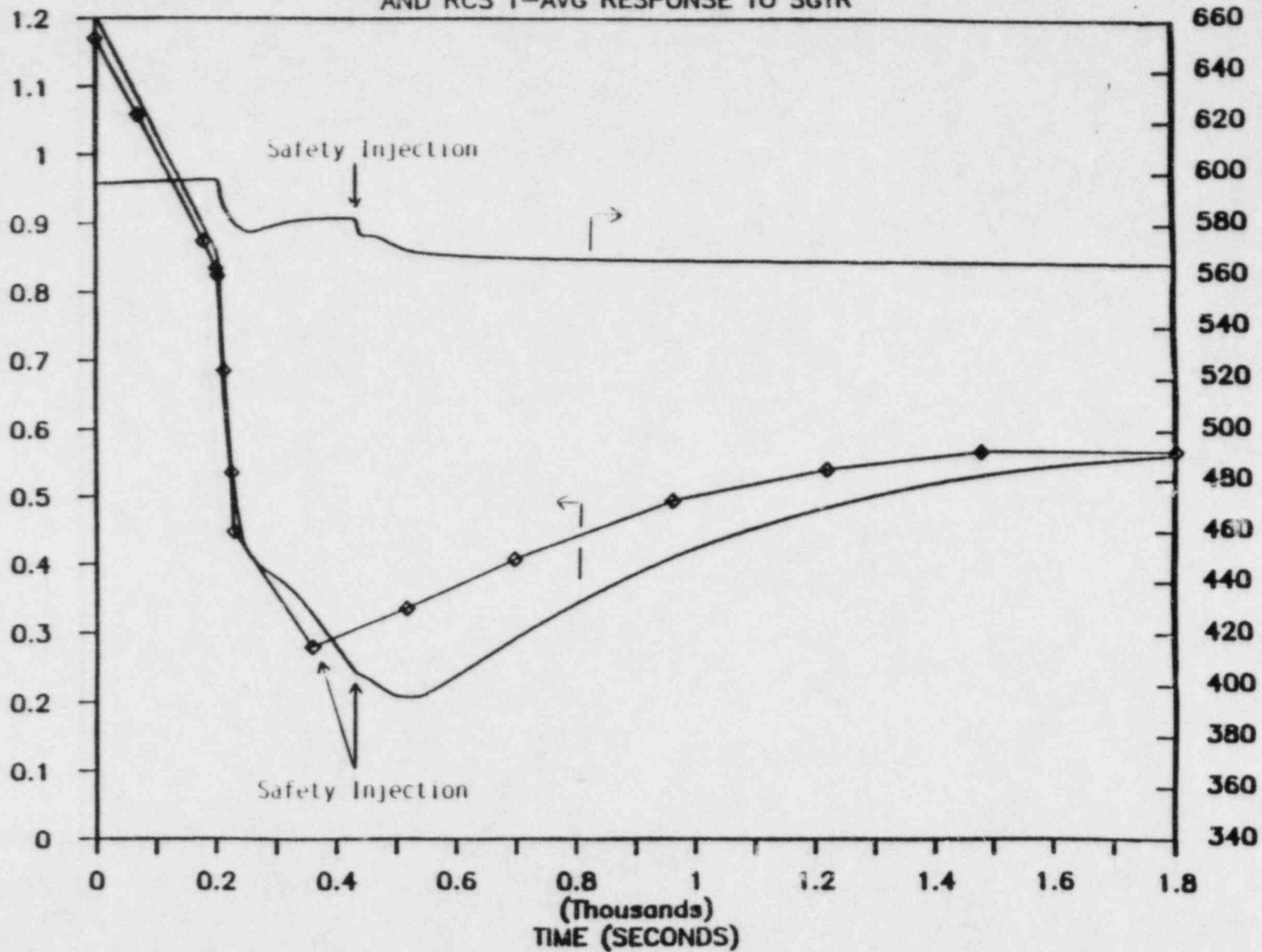


FIGURE C-7

PRESSURIZER WATER VOLUME

AND RCS T-AVG RESPONSE TO SGTR

C-13
PRESSURIZER WATER VOLUME (FT³3)
(Thousands)



AVERAGE CORE TEMPERATURE (DEG. F)

— RETRAN

◇ FSAR

FIGURE C-8

SGTR FLOW RATE TRANSIENT

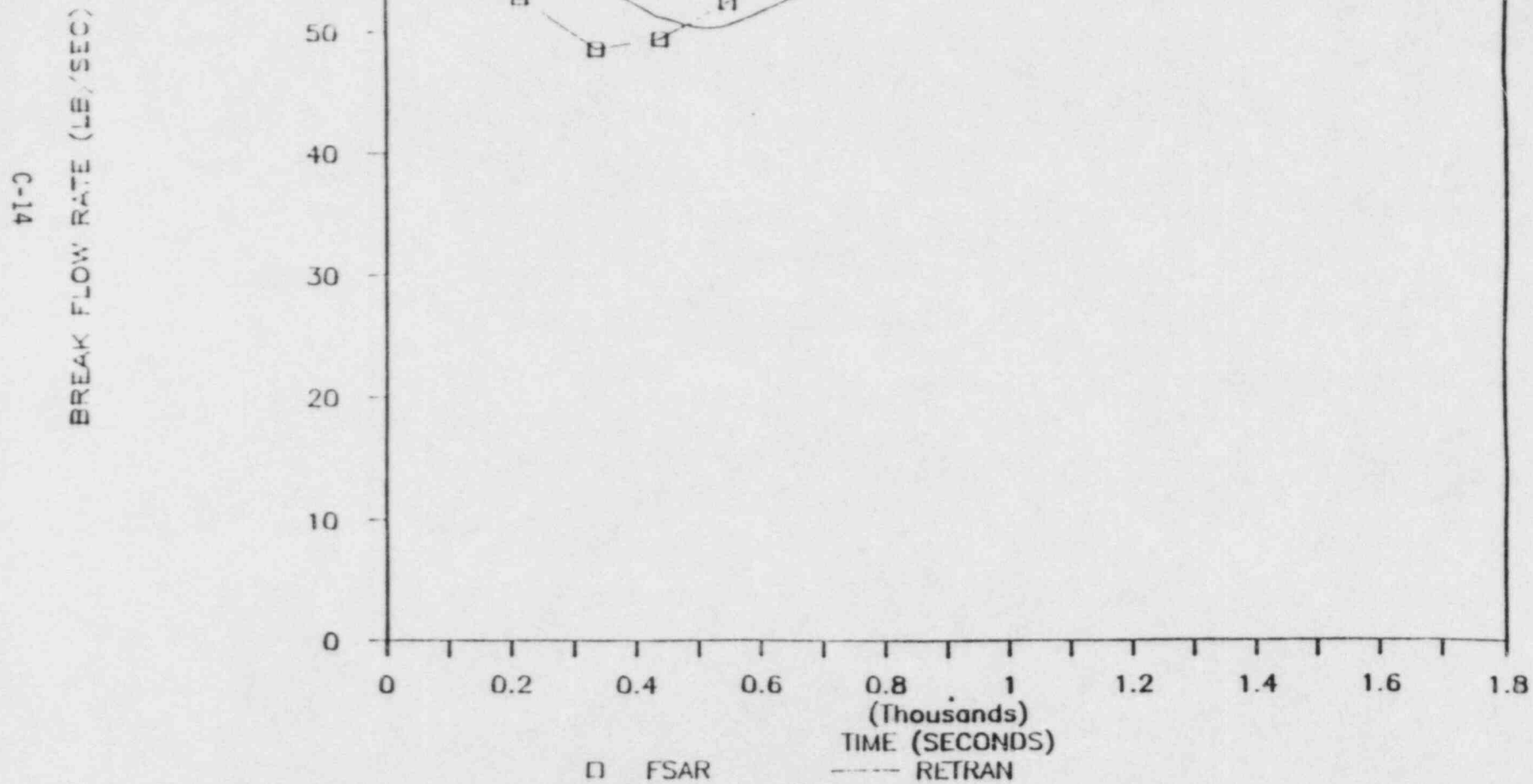


FIGURE C-9

FAULTED S.G. PRESSURE TRANSIENT

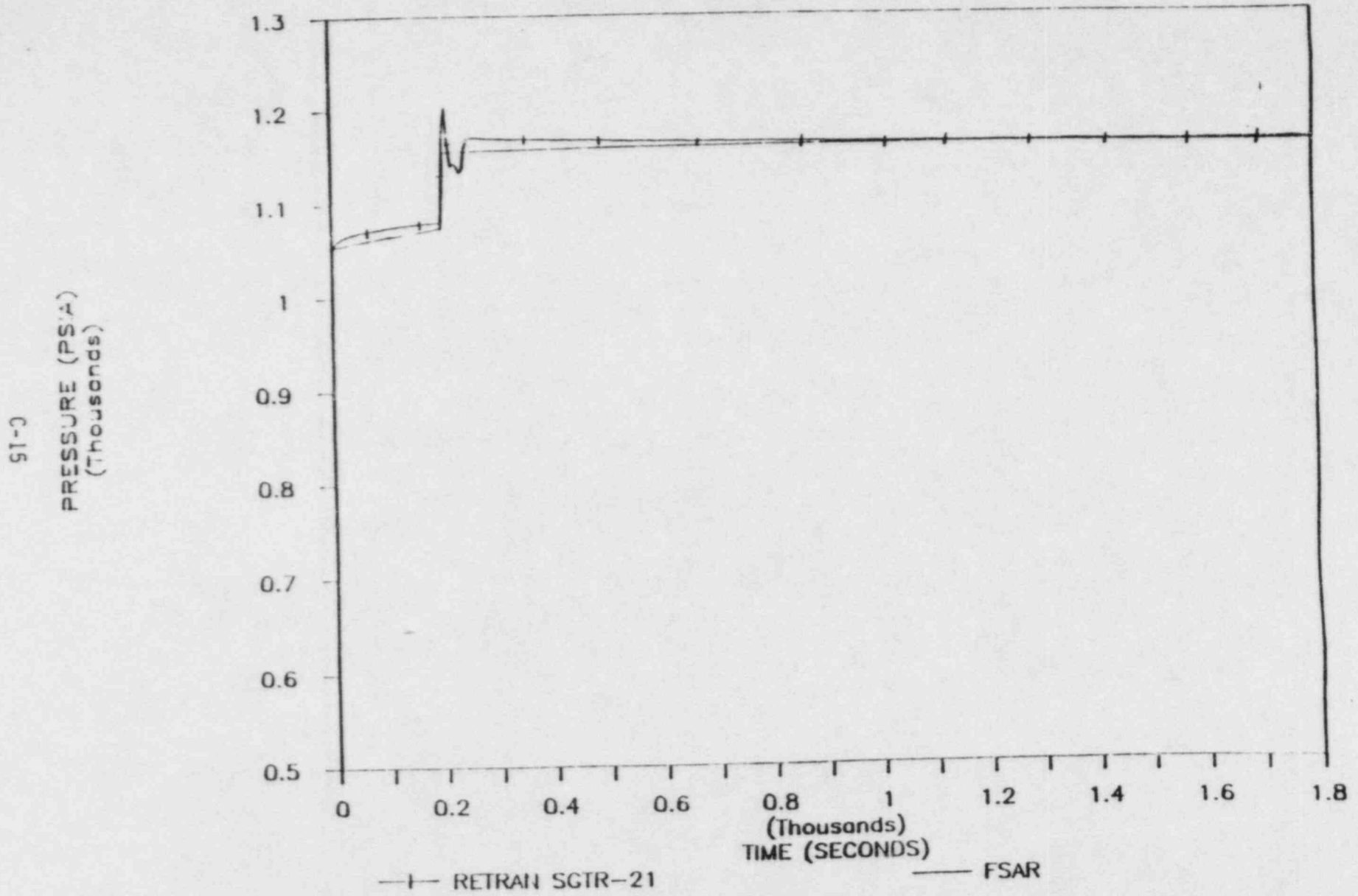


FIGURE C-10

FAULTED S.G. TEMPERATURE TRANSIENT

91-C
TEMPERATURE (DEG. F)

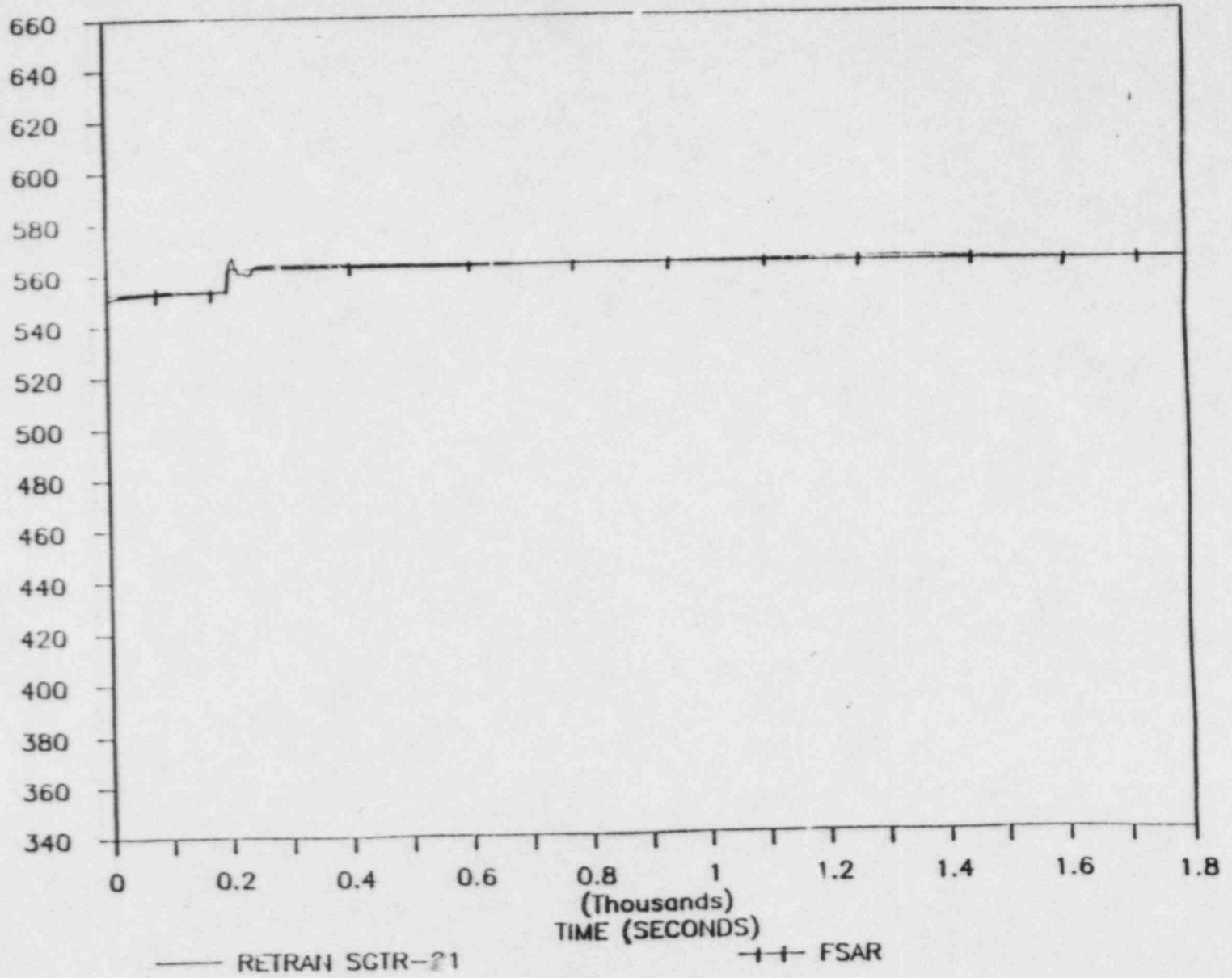


FIGURE C-11

FAULTED S. G. LIQUID MASS TRANSIENT

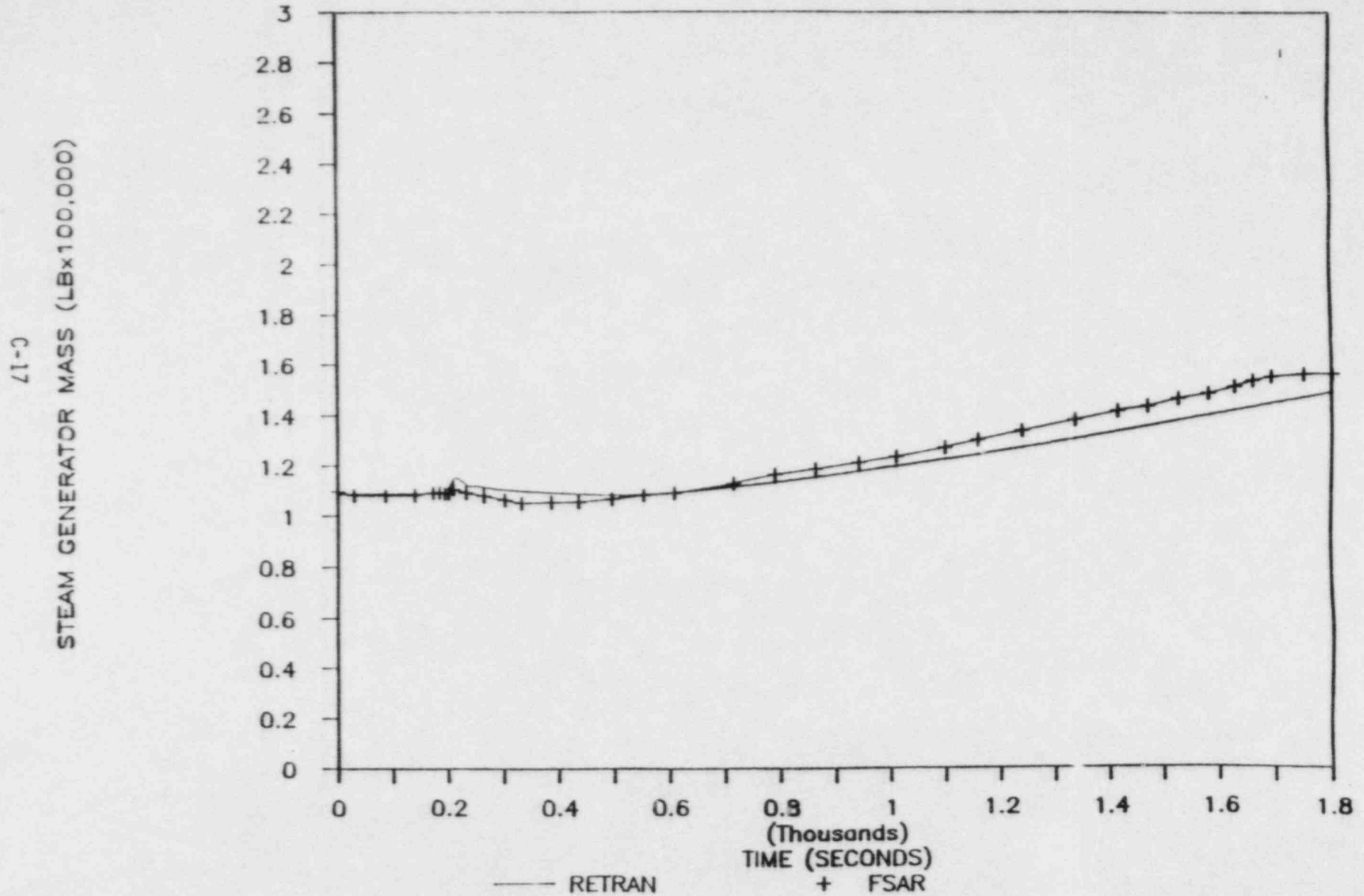


FIGURE C-12

INTACT S. G. LIQUID MASS RESPONSE TO SGTR

C-18

STEAM GENERATOR MASS (LBx100,000)

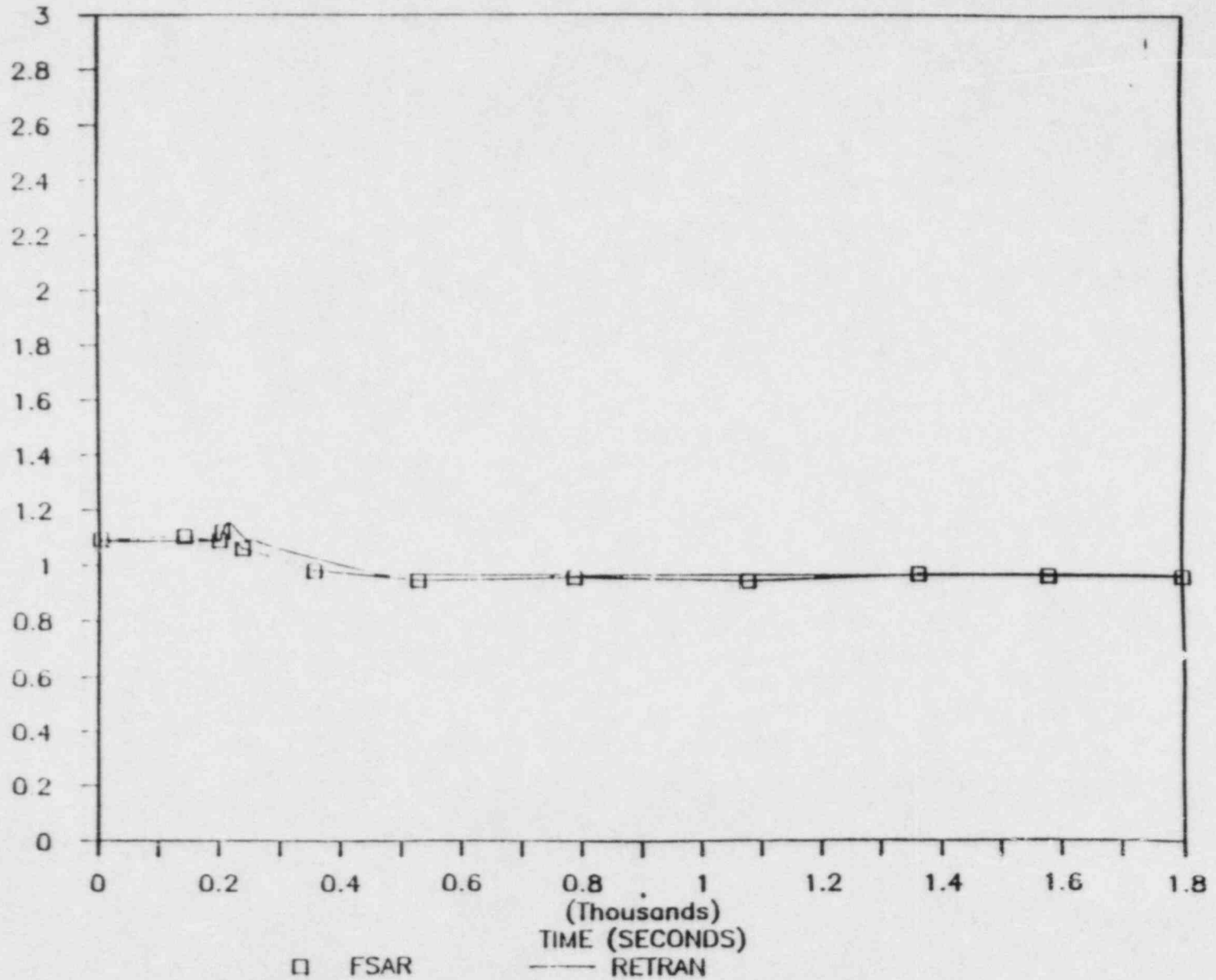


FIGURE C-13

FAULTED S.G. WATER VOLUME TRANSIENT

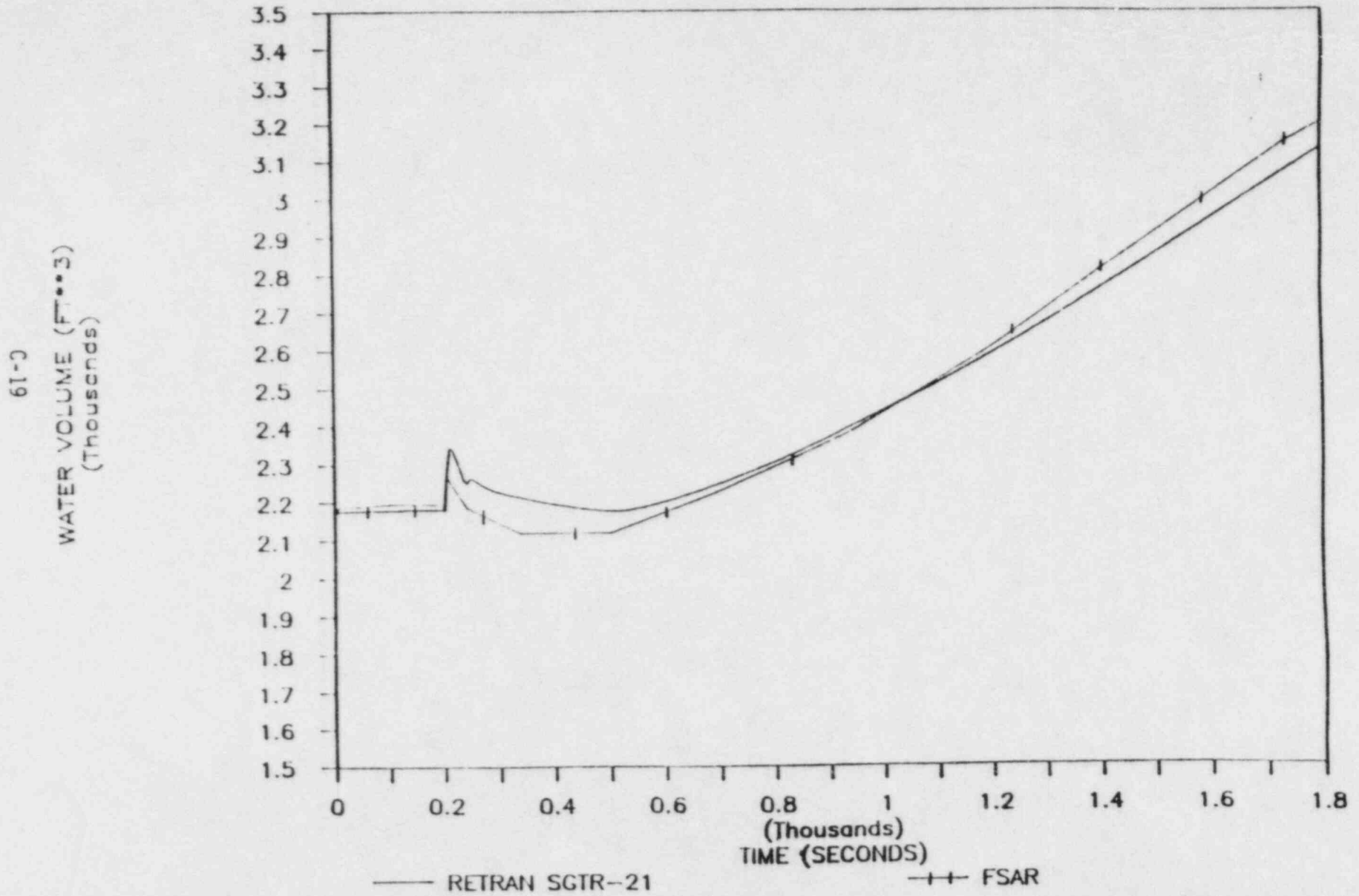
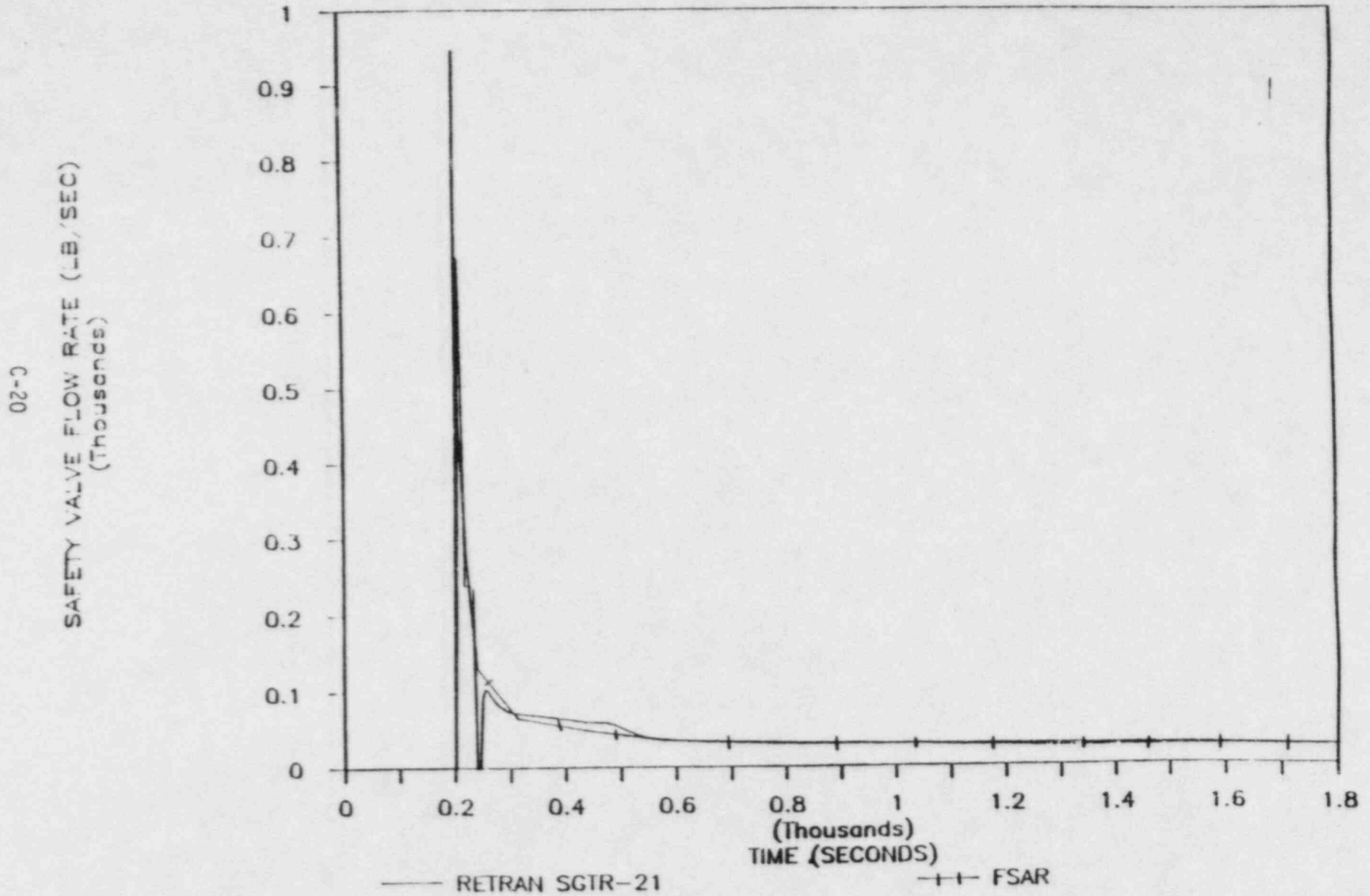


FIGURE C-14

FAULTED S.G. SAFETY VALVE FLOW RATE



Appendix D - Break Flow Model

I. INTRODUCTION

Estimating the break flow from an SGTR event is complicated by many factors, including: the large pressure differentials, the relatively long tube lengths (l/d) and the initially subcooled nature of the primary fluid. Each of these factors is important in determining whether the flow is choked or friction-limited.

The purpose of this appendix is to address this issue and determine which correlation is best suited for describing break flow from an SGTR.

II. CRITICAL/NON-CRITICAL FLOW

Given a pressure differential across a tube, fluid will be drawn through the tube. Initially at small p_s , the flow through the tube will be dependent upon the wall friction (resistance-limited flow). As the pressure differential is increased, however, the flow may experience either sonic or two-phase choking.

In sonic choking, a single-phase fluid, driven by a large p_s , attempts to move faster than the speed of sound in the fluid. At this velocity, though, the downstream pressure signal (wave) can no longer be transmitted to the upstream fluid. As a result, no further flow increase is possible, and the flow is said to be choked. The speed of sound in water at STP is approximately 4,800 ft/sec. For SGTRs, the p_s is not sufficient to achieve sonic choking.

In two-phase choking, the originally subcooled fluid undergoes a pressure drop while transversing the tube which is sufficient to lower the pressure of the fluid below the saturation pressure. At this point the fluid will change phase and expand from a liquid to a vapor. This expansion acts to restrict or choke the fluid flow.

It should be noted that choking places a physical restriction on what otherwise would be friction-limited flow. To show this, consider Figure D-1 which compares estimated flow rates for friction-limited and choked flow correlations as a function of pressure differential.

Where the two curves intersect, choking effects become important. For any pressures to the right of the point of intersection, the flow is choked and physically prevented from achieving the flow rates predicted by the resistance-limited model.

It is standard practice in hydraulics calculations to calculate the flow rate given by friction-limited and choked correlations. The lesser of the two rates is then taken as the true flow rate.

III. Resistance-Limited Equation

If the density change is small throughout the length of the tube, the flow may be calculated conservatively using the following momentum equation:

$$G = \left[\frac{1}{(f \frac{l}{d} + K_{ent} + K_{exit})} \cdot 2g_c \rho \cdot \Delta p \cdot 144 \right]^{1/2}$$

where:

- f = friction factor = function of Reynolds Number and roughness
- l = length of tube, ft
- d = tube diameter, ft
- ρ = incoming fluid density, lbm/ft³
- g_c = gravitational constant = $32.174 \frac{\text{lbm}}{\text{lbf}} \cdot \frac{\text{ft}}{\text{sec}^2}$
- K_{ent} = entrance form loss
- K_{exit} = exit form loss
- G = mass velocity, lbm/ft²sec
- Δp = pressure differential, psi
- 144 = conversion constant, in²/ft²

IV. Choosing the Proper Critical Flow Correlation

Many critical flow correlations exist, each having a range of applicability which is dependent upon factors such as: tube length, l/d, pressure differential (Δp), and/or initial fluid quality. For an SGTR in a SNUPPS plant with rupture of the cold leg of the tube sheet, two unique flow situations exist:

- a. cold leg tube, l/d = 35; subcooled inlet; large pressure drop
- b. hot leg tube, l/d = 952; subcooled inlet; large pressure drop; heat removal over length (cooling).

For either of these situations, the following correlations may be applicable:

- a. Modified Zaloudek (Reference D-1),
- b. Burnell (Reference D-2), or
- c. Henry, 1970 Model (Reference D-3).

Comparisons with data over the range of interest for the SGTR have been performed. It has been concluded that the Burnell correlation most conservatively estimates the critical flow rates with acceptable accuracy for the range of conditions encountered in the steam generator tube rupture event. The Burnell equation is as follows:

$$G_B = [2g_c (\rho_{up} - (1-C)\rho_{SAT}) \cdot 144]^{1/2}$$

where:

ρ_{up} = upstream stagnation pressure, psia

= upstream density, lbm/ft³

ρ_{SAT} = saturation pressure at upstream temperature, psia

144 = conversion factor, in²/ft²

C = Burnell constant (see Figure D-2)

V. Flow in the Long Hot Leg Tube

For the long (hot leg) segment, heat transfer across the tube decreases the fluid temperature during transit. In addition, the fluid will undergo a large pressure drop and a probable phase change while flowing through the long tube ($l/d = 952$).

It was determined that for the range of SGTR conditions experienced, single phase, resistance-limited flow provided a conservatively high mass flow rate. This conclusion was based on comparison to flow rates computed with two phase conditions and heat transfer, as described above.

References

- D-1. Westinghouse Electric Corporation, "Analysis of Plant Response During January 25, 1982, Steam Generator Tube Failure at the R. E. Ginna Nuclear Power Plant," November, 1982.
- D-2. Tong, L.S. and Weisman, J., Thermal Analysis of PWRs, American Nuclear Society, LaGrange Park, IL, 1979.
- D-3. Henry, Robert E., "The Two-Phase Critical Discharge of Initially Subcooled or Saturated Liquid," Nuclear Science and Engineering 41, 336-342 (1970).

FIGURE D-1

Choked Versus Friction-Limited

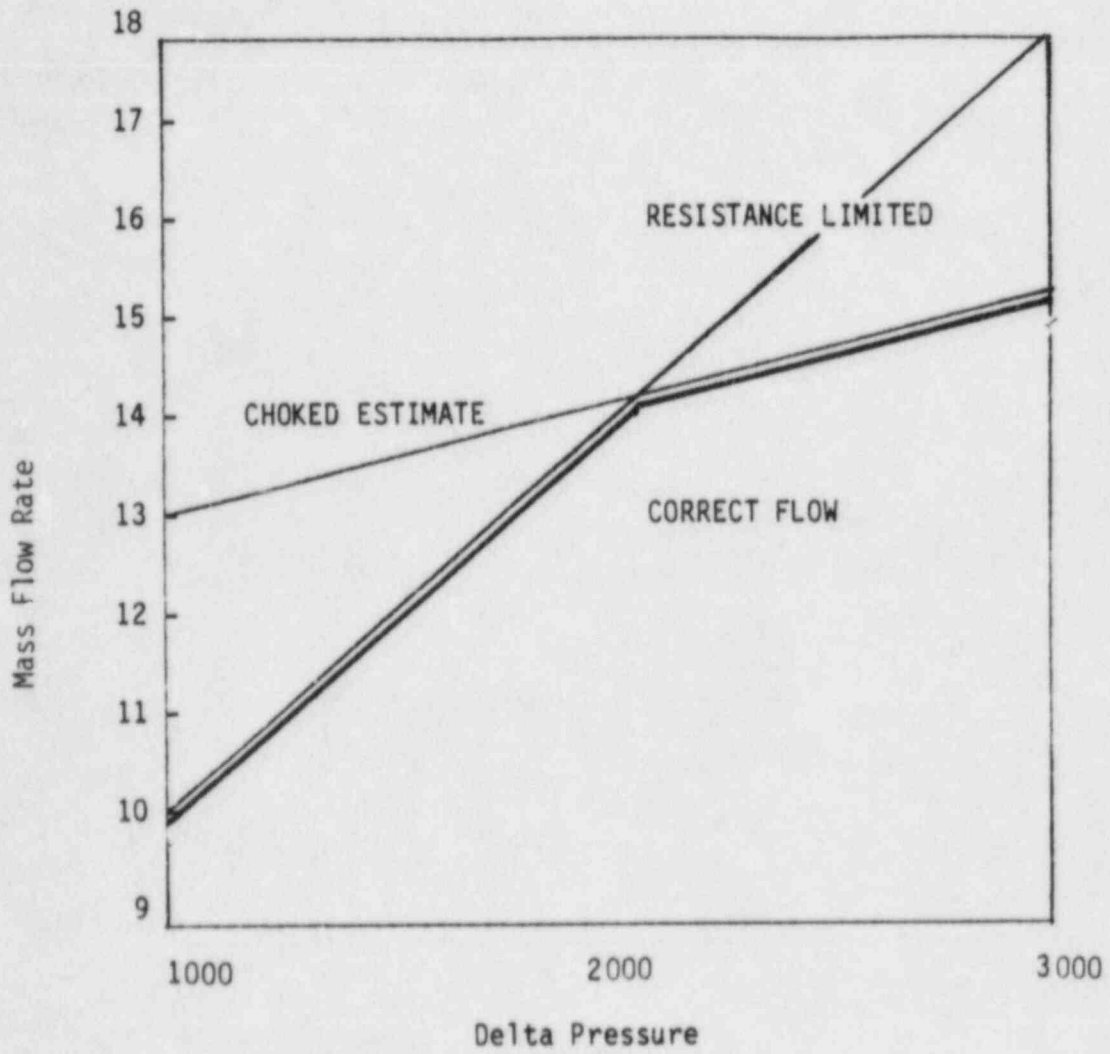
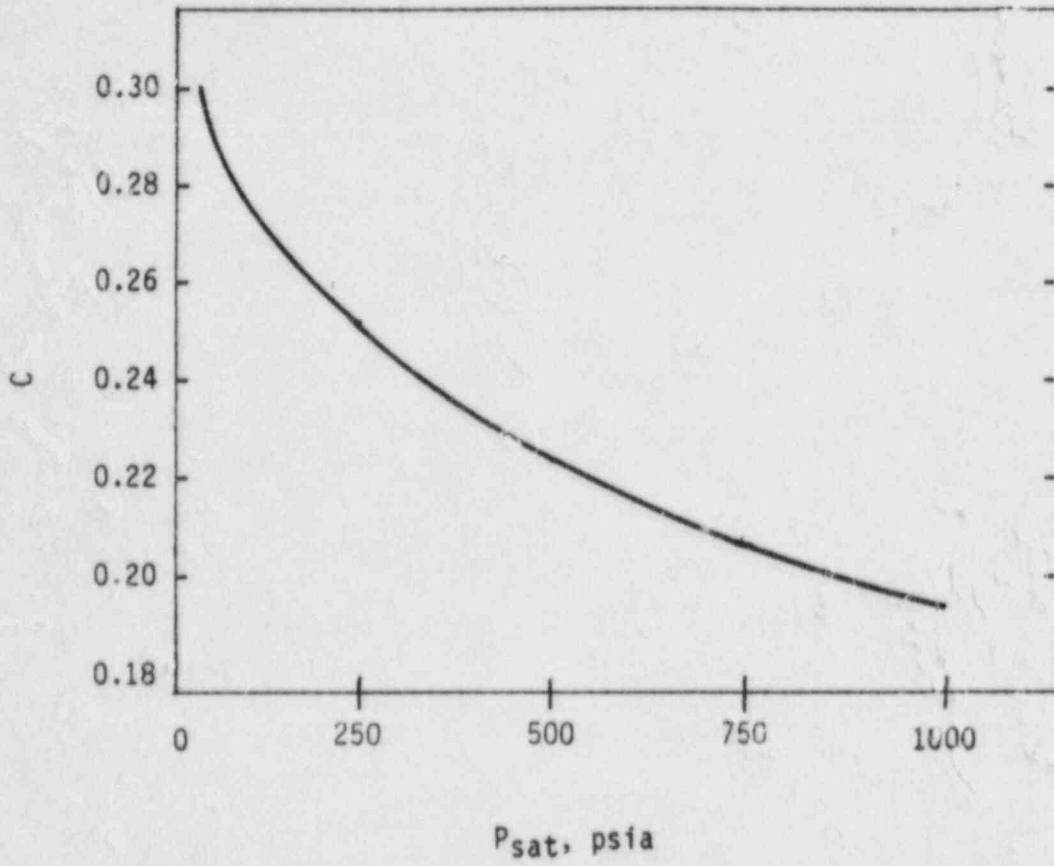


FIGURE D-2



Pressure coefficient for Burnell critical flow equation
(From Engineering, 164, 572 [1947]).

APPENDIX E BASES FOR ATMOSPHERIC RELIEF VALVES TECHNICAL SPECIFICATION

I. Number of Operable ARV's

The operability of the main steam line atmospheric relief valves (ARVs) ensures that reactor decay heat can be dissipated to the atmosphere in the event of a steam generator tube rupture and loss of offsite power and that the Reactor Coolant System can be cooled down for Residual Heat Removal System operation. Only one ARV is needed for the heat removal required. Three operable ARVs are adequate, assuming that one of the operable valves is on the faulted steam generator and that one ARV fails to function.

II. More than One Inoperable ARV

Each ARV is equipped with a manual block valve (in the auxiliary building) to provide a positive shutoff capability should an ARV develop leakage. An ARV is considered operable if the block valve is closed solely because of leakage. Closure of the block valves of all ARVs because of leakage does not endanger the reactor core; decay heat can be dissipated with the main steam line safety valves or a block valve can be opened manually in the auxiliary building and the ARV can be used to control release of steam to the atmosphere. Primary to secondary leakage can be terminated by depressurizing the Reactor Coolant System with the pressurizer power operated relief valves.

Appendix F - Radiological Consequences

1. Abstract

This appendix describes the methods used to calculate radioactivity releases to the atmosphere and offsite doses for postulated SGTR events. Two cases of iodine spiking, as prescribed by Standard Review Plan 15.6.3, are considered. Radioactivity releases are based on the results of RETRAN calculations, given in Section 4, up to the time of SI termination and supplementary calculations thereafter. Offsite doses are calculated in accordance with the methodology described in Appendix 15A of the FSAR.

2. Reactor Coolant Activities

Concentrations of five iodine isotopes and thirteen noble gas isotopes are initially normalized to a dose-equivalent I-131 concentration of $1 \mu\text{Ci/g}$. This is done by scaling up by a constant factor (1.221) the iodine and noble gas concentrations for 0.25% fuel defects, as given in Table 11.1-4 of the FSAR. As a result, the initial iodine concentrations satisfy the relationship:

$$\sum C_i A_i = 1 \mu\text{Ci/g}$$

where: C_i = concentration of i th isotope of iodine

A_i = ratio of dose conversion factors as provided in References 1 and 2.

Steady-state release rates from the fuel for each of the 18 isotopes are then determined for the calculated reactor coolant concentrations, assuming there is a steady-state letdown flow of 75 gpm.

These base values of reactor coolant concentrations and release rates are given in Table F-1.

Iodine spiking is introduced, in accordance with SRP 15.6.3. For Case 1 (accident induced spike), the steady-state release rate of each iodine isotope is increased by a factor of 500, when the reactor trips. For case 2 (pre-existent iodine spike), the initial concentrations of the five iodine isotopes at the time of occurrence of the SGTR are 60 times the values given in Table F-1.

Concentrations of iodine and noble gas isotopes in the reactor coolant are assumed to remain constant until the reactor trips. After reactor trip, the concentrations are calculated assuming release rates from the fuel, as discussed above, and removal by radioactive decay, break flow to the faulted SG, and leakage flow to the intact SGs. Throughout the accident duration, it is conservatively assumed that the mass of water in the reactor coolant system remains constant. Actually, the mass increases by virtue of cooldown during the transient, which results in slightly lower isotope concentrations than calculated.

3. Secondary Side Activities

The initial concentrations of five iodine isotopes in SG water are normalized to a dose-equivalent I-131 concentration of $0.1 \mu\text{Ci/g}$, in accordance with SRP 15.6.3. The resultant concentrations are 1/10 of the values given in Table F-1. The noble gas concentrations are assumed to be zero. That is, noble gas activity entering the secondary side is assumed to be released immediately to the atmosphere.

After occurrence of the SGTR, the iodine concentrations in the water in the faulted and intact SGs are calculated considering addition of activity from the RCS by break flow or leakage and removal by radioactive decay. The secondary side concentrations are also adjusted for changes in the mass of water in the SG. Removal of activity by carryover with steam is conservatively neglected in calculated radioactivity concentrations in the water, but is considered in calculating releases to the atmosphere.

4. Application of RETRAN and Supplementary Analyses

The following results, obtained from RETRAN and supplementary analyses, are used to evaluate the radiological consequences of a postulated SGTR.

- Time sequence of events
- RCS pressure and temperatures
- Secondary side pressures in faulted and intact SGs
- Break flow to faulted SG
- Auxiliary feedwater addition to faulted and intact SGs
- Steam release from faulted and intact SGs

RETRAN calculations have been performed to the time of S1 termination (Section 4). After termination of S1, conditions in the plant change relatively slowly and supplementary calculations are adequate to extend the analyses to 2 and 8 hours after occurrence of the SGTR.

The calculation of radiological consequences is divided into 8 time intervals, as follows:

- (1) SGTR occurrence to reactor trip
- (2) ... to isolation of faulted SG
- (3) ... to start of cooldown of RCS
- (4) ... to start of RCS depressurization
- (5) ... to end of RCS depressurization
- (6) ... to 5 minutes after S1 termination
- (7) ... to 2 hours after SGTR
- (8) ... to 8 hours after SGTR

Over each interval, the plant parameters listed above are assumed to be constant. The values used in the analyses are listed in Tables F-2 and F-3.

Break flow from the hot and cold legs of the faulted SG and the fractions of break flow that flash upon reaching the secondary side are taken from the RETRAN analyses.

The break flows are used in the calculations of RCS and secondary side iodine concentrations and in releases of noble gases. AFW flows are used in the calculation of secondary side water inventories, which affect iodine concentrations. Steam release rates are used directly to calculate radioactivity releases. Flashed fractions of the break flow are also used in the radioactivity release calculation.

After termination of SI, it is assumed, as discussed in Section 4, that within 5 minutes the operators equalize RCS and faulted SG pressures. The integrated break flow during that time is calculated by extrapolation of the RETRAN results. After break flow is terminated, it is assumed that the operators keep the pressure in the faulted SG balanced with RCS pressure, so that there is no further break flow. However a 1 gpm leakage flow from the RCS to the intact SGs is assumed to continue throughout the duration of the accident.

Auxiliary feedwater flow to the faulted SG is assumed to be zero from termination of SI until the end of the accident. Auxiliary feedwater to the intact SGs is assumed to continue, for decay heat removal, and to be equal to the steam released.

Steam release from the faulted SG during the transition to RHR cooling is assumed to be zero for the case of potential overfill, because the procedural guidance (Section 2) is to cool the faulted SG and make the transition to RHR cooling by backfill or SG blow-down. However, for the other case analyzed (worst case dose), it is assumed, in order to envelope the dose consequences, that the faulted SG is cooled and depressurized by steam release to the atmosphere. A supplementary calculation, assuming adiabatic depressurization, was used to calculate the amount of steam released while reducing the faulted SG pressure to 300 psia.

Steam releases from the intact SGs, after termination of SI, have been calculated on the basis that steam is released and an equal mass of AFW is added to remove decay heat up to 8 hours after the SGTR and to depressurize the intact SGs to 300 psia prior to initiating RHR cooling.

5. Radioactivity Releases

Iodine releases to the atmosphere are calculated to be the sum of the following:

- (1) 1% of the iodine concentration in the SG water times the mass of steam released from the SG.

- (2) 100% of the iodine contained in the fraction of the break flow to the faulted SG that flashes upon reaching the secondary side. (This term is conservatively included even when the RETRAN analysis shows that no steam is released from the secondary side ARVs or safety valves).

The 1 gpm leakage flow to the intact SGs is assumed not to flash. Thus, only the first of the above terms applies to the intact SGs.

Noble gas releases to the atmosphere are calculated to be equal to 100% of the noble gas contained in reactor coolant break flow or leakage flow that reaches the secondary side. This conservatively assumes no retention in the SG water.

6. Doses

The 0-2 hour site boundary and 0-8 hour exclusion boundary doses to the thyroid and whole body are calculated in accordance with Appendix 15A of the FSAR and adult conversion factors were utilized. That is, contributions of five iodine isotopes and thirteen noble gas isotopes are summed to obtain the total doses. Values of X/Q applicable to the Callaway plant have been used, because these values are higher than those for the Wolf Creek Station and result in higher calculated doses.

References

1. Callaway Plant Chemistry Technical Procedure CTP-ZZ-02540, "Determination of Isotopic Specific Gamma Activity in Liquids", Revision 5, dated 3/30/85
2. Wolf Creek Generating Station Procedure CHMO 3-052, Revision 2, "Determination of Radioactive Iodine and Dose Equivalence Iodine Analyzers."

Table F-1

Base Values of Reactor Coolant Concentrations
and Release Rates from Fuel

<u>Isotope</u>	<u>RCS Concentration (μ Ci/g)</u>	<u>Release Rate From Fuel (μ Ci/sec)</u>
I-131	6.874 - 01	2.567 + 03
I-132	2.539 - 01	5.660 + 03
I-133	9.667 - 01	5.386 + 03
I-134	1.195 - 01	6.297 + 03
I-135	4.835 - 01	4.785 + 03
Xe-131m	4.859 - 02	1.780 + 02
Xe-133m	2.649 - 01	1.140 + 03
Xe-133	1.319 + 01	5.077 + 04
Xe-135m	3.590 - 02	6.003 + 03
Xe-135	7.863 - 01	6.435 + 03
Xe-137	2.491 - 02	1.682 + 04
Xe-138	1.209 - 01	2.228 + 04
Kr-83m	5.543 - 02	1.465 + 03
Kr-85m	2.747 - 01	3.641 + 03
Kr-85	2.051 - 02	7.206 + 01
Kr-87	1.611 - 01	6.016 + 03
Kr-88	5.165 - 01	9.738 + 03
Kr-89	1.380 - 02	1.163 + 03

Table F-2

Plant Parameters** Used in Calculation of Radiological Consequences
(Worst Case Dose)

<u>Time interval*</u>	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>	<u>6</u>	<u>7</u>	<u>8</u>
End time (sec)	503	1705	2397	3203	3300	3781	7200	28800
Liquid Mass fltd SG (lb)	103300	84000	116000	166000	184000	190000	190000	190000
Break Flow (lb/sec)	42	43	50	48	25	13.5	0	0
Flashed Fraction of Break Flow	0.146	0.087	0.041	0	0	0	0	0
Steam release fltd SG (lb/sec)	1050 [•]	111	0	0	0	0	7.9	0
Steam release intact SG (lb/sec)	1050 [•]	71	0	182	0	0	40	29

**Values tabulated are averaged over interval

*See Appendix F, Section 4

[•]Steam flow to turbine

Reactor coolant mass assumed constant at 490000 lbs.

Table F-3

Plant Parameters** Used in Calculation of Radiological Consequences
(Worst Potential Overfill)

<u>Time Interval*</u>	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>	<u>6</u>	<u>7</u>	<u>8</u>
End Time (sec)	146	961	1441	2031	2103	2583	7200	28800
Liquid mass fltd SG (lb)	107000	156000	228000	250000	261000	267000	267000	267000
Break Flow (lb/sec)	43	40	46	38	18	13.5	0	0
Flashed Fraction of Break Flow	0.069	0.021	0.007	0.001	0	0	0	0
Steam release fltd SG (lb/sec)	1100*	192	0	0	0	0	0	0
Steam release intact SG (lb/sec)	3300*	60.6	0	100	0	0	51	36.6

**Values tabulated are an average over interval

*See Appendix F, Section 4

•Steam flow to turbine

Reactor collant mass assumed constant at 490000 lbs.